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CO2 Capture Project

Final Technical Report

Long-Term CO_2 Storage
Using Petroleum Industry Experience

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ABSTRACT/EXECUTIVE SUMMARY

This project comprised a survey of Permian Basin reservoirs that were either injected with CO_2 or were at least seriously considered for CO_2 injection. The focus being on an assessment of successes and problems in these projects and their long-term CO_2 storage potential. This project did not undertake extensive reservoir engineering studies. Subsequent phases could include expansion into gas injection projects throughout the remainder of the United States and/or in-depth studies of selected reservoirs. This data includes information from the biannual *Oil & Gas Journal* EOR Survey, Society of Petroleum Engineers publications, and CO_2 field project engineers representing all but two of the CO_2 injection project operating companies.

There is significant experience and knowledge in the industry to separate, compress, transport, inject, and process the quantities of CO_2 that are envisioned for CO_2 sequestration/storage. Improvements will occur as incentives, time and fluid volumes increase. The most important requirement is the provision of incentives to sequester CO_2.

In some cases certain phenomena that had been noted during waterflood was not included in simulating CO_2 processes—an omission that can prove, and has proven, disastrous. When reservoir characterization is well understood, CO_2 has performed as expected. Also, the phase properties 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 and when pressure drops as it advances through the reservoir precipitants can form. However, the kinetics of dissolution and precipitation under many reservoir conditions require further study.

In the short geological time frame that CO_2 has been actively injected into geological formations, seals are maintaining their integrity and retaining CO_2 in place. Proven seals perform as expected in retaining CO_2. Monitoring and verification of CO_2 flow in geological formations is critical to verification of sequestration, but technical development is in its infancy.

Surface safety was not specifically covered in this discussion, but warrants review. In working for over twenty-two years in the area of CO_2 production, transportation, and injection into geological formations of significant quantities of CO_2, I have not heard of one fatality. Safe transportation of CO_2 and other high-pressure gases warrants great optimism that global transport of CO_2 on an enormous scale would be accomplished at very low risk.

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INTRODUCTION

The petroleum industry has been injecting carbon dioxide (CO_2) into geological formations for about fifty years. The bulk of this injection, taking place over the last two decades, has not been for sequestration/storage, but to displace/dissolve oil for increased oil production. Currently, about 2 billion standard cubic feet per day (BCFD) 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 an oil reservoir, the majority of the floods cannot be considered sequestration/storage projects because the CO_2 source is another geological formation. Geological formations presently producing high purity CO_2 for IOR are in southwest Colorado (McElmo Dome), southeast Colorado (Sheep Mountain), northeast New Mexico (Bravo Dome), and Mississippi (Jackson Dome). Combined, these produce about 1.5 BCFD or 32,000,000 tons per year. There are a number of notable exceptions in which the CO_2 source is an industrial by-product. Projects in Michigan, A 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 fields are exceptions and can be considered CO_2 sequestration/storage projects. These projects have the capacity to supply over 0.5 BCFD or 11,000,000 tons per year. Even though many of the IOR projects can not be considered more than environmentally neutral as green house gas storage, the experience of operators from injecting CO_2 in diverse oil-bearing reservoirs and the potential storage capacity of oil reservoirs are resources that to be tapped for CO_2 sequestration knowledge and future storage potential.

During this project, we identified over 135 reservoirs into which CO_2 is being injected or has been injected into, or the operating company has indicated that there would be a future flood. These include:

- 70 field projects that are in operation.
- 47 terminated projects, of which at least 20 were only field 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 others 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 initiated and at this time do not seem to be headed toward any type of IOR project.

These projects represent a number of geographic areas in the lower 48 States of the United States (USA). The states that have or have had projects are listed in Table 1 with number of total projects and active projects indicated. Besides the miscible projects, at least 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. The injection time varied from a few months for some pilots to about thirty years for some field projects. These numbers do not include the numerous fields seriously 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

State	Total Projects	Active Projects
Alabama	1	0
California	2	0
Colorado	2	1
Kansas	1	1
Louisiana	10	0
Michigan	2	2
Mississippi	4	3
Montana	1	0
New Mexico	8	3
North Dakota	1	0
Oklahoma	6	5
Pennsylvania	2	0
Texas	80	47
Utah	3	3
West Virginia	2	0
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. Thirty different organizations have operated CO_2 projects in the Permian Basin. Projects have been performed in sandstone, limestone, and dolomite reservoirs, with over half located in San Andres formations. 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 study to assess the effects and long term potential of CO_2 storage in geological formations.

This type of study becomes more difficult to analyze as time progresses, because of mergers and personnel changes that will result in lost or limited access to valuable information. This was seen in a number of cases. For example, fields such as South Huntley and Ford Geraldine have changed operators since termination and little information was derived from the new operator. Another example is the former Amoco and Shell properties now owned by Oxy that has chosen not to participate in questions that are subject to interpretation. Information from earlier publications and interaction with engineers before the sale were available, but nothing since the purchase.

This study was not carried out as a simple survey/questionnaire but included visits to the engineering center sites and/or archives of the appropriate operating companies to gather information and obtain clarifications. The goal was 100% coverage, with a minimum of 75% since it was not assured that all operators would participate. The final results had a high level of participation from the operators, but a lower than hoped for number of fields examined, because two operators that have chosen not to participate have considerable holdings.

To maximize participation, this project used an email questionnaire and phone contact to initiate the study of each reservoir. This was followed by an onsite visit to all engineering center that would participate. The onsite visits were used to minimize a participant’s time commitment and maximize the information obtained and the understanding of the information. To encourage participation project results will be available to each participant that shared information.

EXPERIMENTAL APPROACH

Steps that were taken to identify and analyze the work of many years in the area of CO_2 injection into reservoirs in the Permian Basin included:

1. The initial identification of CO_2 field projects taken from the biannual EOR Survey published in the *Oil & Gas Journal* in each even year since 1978. These surveys always list present projects, including pilot and full scale projects and often mentioned announced future projects and projects terminated since the last publication.
2. Identification of those projects in "1" above which are within the study area comprising the Permian Basin.
3. A literature search on the projects in "2", with most of the literature directly related to the CO_2 projects being contained in Society of Engineer conferences and publications.
4. Selection of a number of parameters, items, and questions to determine or answer for each project.
5. Gathering information out of 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 visit to each engineer that would accommodate us.
7. Analysis of information in hand in order to aid those considering CO_2 injection into a geological formation.
8. Finally, we interpreted the information obtained from each engineer and literature source. This information though based on data gathered from reliable sources, cannot be used 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 150 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 was the operator ever intending 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 project or several pilot projects in the same field into one spreadsheet. Table 2 is the final 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 (Grigg, 1996 PRRC Survey).

3. About two-thirds of the projects listed in Table 2 have published articles related to CO_2 injection. Appendix A contains the references to the *Oil and Gas Journal* biannual EOR Summaries and then the SPE papers for each field. In Appendix A the CO_2 projects are arranged alphabetically by state and field name with SPE paper numbers and titles. The second half of Appendix A contains an abstract for each SPE paper.
4. Appendix B contains a spread sheet for each reservoir listed in Table 2. An asterisk in the first column in each spread sheet indicates the items that we were most interested. The second column contents are the information requested. The third column lists the information obtained. The fourth column has information gathered to indicate the pore volume of the reservoir, hydrocarbon volume, and stock tank oil volume. Default values are 50 feet of pay, unit area of 1000 acres, average porosity fraction of 0.1, original water saturation fraction of 0.2, and formation volume factor of 1.2.
5. The spreadsheets in Appendix B contain data collected from the literature and CO_2 project engineers.
6. Listed below are some general observations from this study. Some of these probably seem intuitive. More details are listed in the following sections.
    a. Many of the problems that have been encountered could have been avoided or at least anticipated and minimized with better reservoir characterization. This could become more severe when injecting CO_2 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 to the project engineer when starting injection of a fluid such as CO_2.

b. The flow paths of the CO_2 are not always well understood.

c. Retention of CO_2 is significant in most reservoirs.

d. CO_2 injectivity is often lower than expected and in many cases is a critical parameter when considering economics.

e. In one reservoir that has been CO_2 flooded it is about to be plugged and abandoned the produced CO_2 is being injected into a brine aquifer.

f. In many cases CO_2 saturated water seems to be reacting and might be at least part of the cause of significant formation injectivity changes.

g. In talking to the engineers, there is much to be learned in order to understand the long range implications of CO_2 injection and storage in geological formations.

Table 2. CO_2 Flooded Fields in the Permian Basin.

Total #	**State Total**	**State**	Unit	**Current Operator**	**Current Status**
1	1	New Mexico	Central Vacuum	ChevronTexaco	Operating
2	2	New Mexico	East Vacuum	ConocoPhillips	Operating
3	3	New Mexico	Leamex	ConocoPhillips	Pilot Term.
4	4	New Mexico	Loco Hills	Yates	Pilot Term.
5	5	New Mexico	Maljamar Pilot & Field	ConocoPhillips	Terminated
6	6	New Mexico	North El Mar	Quay Valley	Never started
7	7	New Mexico	North Hobbs	Oxy	Future
8	8	New Mexico	Philmex	ConocoPhillips	Pilot Term.
9	9	New Mexico	Ranger Lake	ConocoPhillips	Never started
10	10	New Mexico	State 35 Unit (Hale Mable)	ConocoPhillips	Operating
11	11	New Mexico	VGSAU	ChevronTexaco	Future
12	1	Texas	Adair San Andres	Amerada Hess	Operating
13	2	Texas	Anton Irish	Oxy	Operating
14	3	Texas	Bennett Ranch	Oxy	Operating
15	4	Texas	Brahaney	Apache	Future
16	5	Texas	Brahaney Plains	Apache	Future
17	6	Texas	Cedar Lake	Oxy	Operating
18	7	Texas	Cogdell	Oxy.	Operating
19	8	Texas	Cordona Lake	ExxonMobil	Operating
20	9	Texas	Dollarhide (Devonian)	Pure	Operating
21	10	Texas	Dollarhide (Clearfork "AB")	Pure	Future
22	11	Texas	East Ford	Orla Petco	Operating
23	12	Texas	East Huntley	Southwest Royalty	Terminated

Total #	State Total	State	Unit	Current Operator	Current Status
24	13	Texas	East Penwell (SA)	First Permian	Operating
25	14	Texas	El Mar	Oxy	Operating
26	15	Texas	Ford Geraldine	Primrose Operating	Terminated
27	16	Texas	Garza	George R. Brown	Terminated
28	17	Texas	GMK South	ExxonMobil	Operating
29	18	Texas	Goldsmith	ChevronTexaco	Field Demo
30	19	Texas	Hanford	Fasken	Operating
31	20	Texas	Hanford East	Fasken	Operating
32	21	Texas	Hansford Marmaton	Stanberry Oil	Terminated
33	22	Texas	Jess Burnes	ConocoPhillips	Never started
34	23	Texas	Kingdom Abo	ChevronTexaco	Terminated
35	24	Texas	Levelland	Oxy	Pilots Term.
36	25	Texas	Levelland	ExxonMobil	Never started
37	26	Texas	Mabee	ChevronTexaco	Operating
38	27	Texas	McElroy	Southland Royalty	Terminated
39	28	Texas	McElroy	ChevronTexaco	Field Demo
40	29	Texas	Means (San Andres)	ExxonMobil	Operating
41	30	Texas	Mid Cross-Devonian	Oxy	Operating
42	31	Texas	North Cowden	Oxy (four pilots)	Pilots Term.
43	32	Texas	North Cross (Crossett)	Oxy	Operating
44	33	Texas	North Dollarhide	Oxy	Operating
45	34	Texas	North Farnsworth	Stanberry Oil	Terminated
46	35	Texas	North Hansford Cherokee	Dorchester	P & A
47	36	Texas	North Van Rueder	Apache	Never started
48	37	Texas	North Ward Estes	ChevronTexaco	Terminated
49	38	Texas	Rankin	Petromac Inc.	Pilot Term.
50	39	Texas	Reeves	Devon	Never started
51	40	Texas	Reinecke	Pure	Operating
52	41	Texas	Robertson (Central and N.)	Oxy	Future
53	42	Texas	Russell	ExxonMobil	Never started
54	43	Texas	Sable	Whiting	Terminated
55	44	Texas	SACROC	Kinder Morgan	Operating
56	45	Texas	Salt Creek	ExxonMobil	Operating
57	46	Texas	Seminole -Main Pay	Amerada Hess	Operating
58	47	Texas	Seminole -ROZ Phase 1	Amerada Hess	Operating
59	48	Texas	Sharon Ridge	ExxonMobil	Operating
60	49	Texas	Slaughter Alex Estate	Oxy	Operating
61	50	Texas	Slaughter Central Mallet	Oxy	Operating
62	51	Texas	Slaughter Estate & Pilot	Oxy	Operating
63	52	Texas	Slaughter Frazier	Oxy	Operating
64	53	Texas	Slaughter HT Boyd Lease	Anadarko	Operating
65	54	Texas	Slaughter (started June-89)	ExxonMobil	Operating
66	55	Texas	Slaughter (started May-85)	ExxonMobil	Operating

Total #	State Total	State	Unit	Current Operator	Current Status
67	56	Texas	Slaughter Sundown	ChevronTexaco	Operating
68	57	Texas	South Cowden	ConocoPhillips	Operating
69	58	Texas	South Cowden (Emmons)	ConocoPhillips	Future
70	59	Texas	South Cross (Crossett)	Oxy	Operating
71	60	Texas	South Huntley	Southwest Royalty	Terminated
72	61	Texas	South Welch & Pilots	Oxy	Operating
73	62	Texas	Spraberry Trend	Pioneer	Pilot
74	63	Texas	T-Star	Oxy	Operating
75	64	Texas	Twofreds-East & West	EOG	Operating
76	65	Texas	University Waddell	ChevronTexaco	Terminated
77	66	Texas	Wasson	ExxonMobil	Operating
78	67	Texas	Wasson Cornell	ExxonMobil	Operating
79	68	Texas	Wasson Denver	Oxy	Operating
80	69	Texas	Wasson ODC & Pilot	Oxy	Operating
81	70	Texas	Wasson South	Oxy	Operating
82	71	Texas	Wasson Willard & Pilot	BP	Operating
83	72	Texas	Wellman	The Wiser Oil Co.	Terminated
84	73	Texas	West Brahaney	Walsh Petroleum	Terminated
85	74	Texas	West Welch	Oxy	Operating
86	75	Texas	Yates	Marathon Oil	Operating
Operating = CO_2 injection project in progress					
Future = Future project					
Never started = Listed as future in the past, but not expected to start up in the foreseeable future.					
Terminated = CO_2 purchase has stopped, while usually production and CO_2 recycle continues.					
Field Demo = First phase developed to evaluate field technical and economical potential.					
Pilot = Small project intended to demonstrate technical feasibility.					
Pilot terminated = A pilot that has been terminated					
P & A = The field has been plugged and abandoned or otherwise truly terminated.					

SUMMARY

The following subsections summarize some results for a number of parameters that were found in the survey sent to engineers for each CO_2 injection project and in subsequent discussions as well.

I. Types of reservoir rock.

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

Table 3. Rock Types

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

II. Types of seals.

The number of respondents to this inquiry was relatively low; this was not a big area of conversation. The integrity of the seal is vital for long term storage. Reservoir engineers were the principle respondents to this study. Many do not worry about the reservoir seal as long as it is sufficient to trap crude oil and are assumed to likewise to trap CO_2. If the oil contains significant amounts of methane and the lighter hydrocarbons it is expected to trap the similar size CO_2. 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. Test in the laboratory of the New Mexico Petroleum

Recovery Research Center (PRRC) under another contract as well as other laboratories have indicated that CO_2 dissolved in brine will react with carbonates. This question and similar ones related to the possibility of losing the seal are being addressed by other Carbon Capture Project (CCP) contracts as well as others in the industry.

Of the twelve responses to the question on type of seals: four indicated that it was only a structure seal, two that it is a salt barrier and six that had seals of evaporite or anhydrites.

Table 4. Seals

Type	Number
Evaporite/Anhydrite	6
Salt	2
Structure	4

III. Injectivity.

In many injection projects, injectivity is a key parameter dictating the success or failure of the process. This fact is shown in this section as well as in later sections discussing problems, concerns, mysteries, and need for focused research. In many reservoirs, injectivity has been lower than expected. The CO_2 and water injectivities during WAG is often lower than the waterflood injectivity. This decrease in injectivity is more dramatic and persistent then predicted when considering relative permeability effects of multiphase flow. As shown in Table 4, the systems that indicated the magnitude of change of brine injectivity all decreased. There were no reports of water injectivity increasing once CO_2 injection occurred. The decreases ranged form 10% to as much as100% 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% to 50% range.

Table 5. Injectivity Changes

Injectivity Changes	Brine	CO_2
None noted	4	5
No comment	7	9
Decreased (Magnitude not indicated)	5	7
Changed (Magnitude indicated)	11	6

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 (5-10% of brine at reservoir conditions) one might expect the injectivity during the CO_2 half-cycle to reach levels much higher than the waterflood injectivity. In most cases brine saturation remains sufficient to reduce the relative permeability to nearer that of waterflood injectivity, but even with this, CO_2 injectivity is expected to be higher than brine. For the six systems reporting, CO_2 injectivity ranged from a decrease of 40% to an increase of 30% with an average near-zero change from waterflood injectivity. This is disappointing when an increase was expected. Again, seven others reported a decrease but did not indicate the magnitude.

One might ask, what does it mean 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 have been maintained. In many cases, whether or not injectivity changed was not determined. Thus there could be a significant decrease in injectivity that is not noted because injectivity was still sufficient for the desired injection rate.

In one reservoir it was noted that in a part of the field there were no injection problems, another area had brine injectivity decrease below the target injection rate, and in a third area both CO_2 and brine injectivity had decreased below the target rates during both half-cycles. 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 good possibility that the project will be injection-limited and injectivity problems must be considered.

IV. ***CO_2 reservoir retention.***

Reservoir CO_2 retention is an important value for storage when combining with improved oil recovery processes. The objective of improved oil recovery 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 this is often not the most economical scenario. In several reservoirs that were relatively homogeneous, it was noted that the sweep was too efficient and the production rate was too slow and/or the timing of a significant oil production increase took too long to obtain the desired rate of return on the capital investment was too low. It appears that sufficient heterogeneity in the reservoirs is necessary for some relatively early oil recovery to recoup investment. Then after breakthrough, some action can be taken to mitigate the heterogeneity problem to 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 the maximum efficiency of the reservoir will play a significant role.

Many of the floods in the Permian Basin are not mature enough to predict final retention. Retention was reported for eight reservoirs. Reported retentions ranged from 38% to 100% with an average of 71%. The reservoir that was reported at 100% was a pilot. Respondents speculate that not enough CO_2 was injected and insufficient time was allowed to have CO_2 breakthrough. After 10 years they still have not seen CO_2 above background. In a more mature reservoir retention was listed as low as, 38%. This is the estimated total amount of CO_2 never seen at the surface once injected, so thus not recycled. Essentially 100% of the purchased CO_2 is still in the system. At the end essentially 100% of the fluid will be stored in a reservoir. The other six were seeing in the range of 60-90% of the CO_2 remaining in the reservoir. These six had an average of 71% retention. These estimates were from reservoirs that have had CO_2 injection from five to 30 years.

In a few cases it was evident that CO_2 did not go where it was expected to go. In these cases engineers made statements such as:

a. It was believed that the CO_2 left the intended flooding area.

b. CO_2 went into an upper and lower zone with much of the reservoir in between untouched. In this case sweep efficiency was less than had been expected.

c. No CO_2 detected after two years of a pilot. After several years it is believed that the area sweep was better than expected and not enough time was allowed or enough CO_2 injected for CO_2 to arrive at the production well.

Each of the three comments above demonstrates that, with better understanding of the reservoir, unexpected results can be minimized.

V. Monitoring/detection methods

One of the more perplexing but essential problems to answer is the ability to track CO_2 thousands of feet below the surface. Even in some of the well-studied reservoirs where the operator thought that they had a good understanding of the geology after the numerous studies done during primary and secondary recovery, surprises have occurred during the low-viscosity CO_2 injection. Understanding the reservoir can mean significant differences in cost. In the case of storage this is a long term effort that must have a cost-effective method to detect movement of CO_2 in geological formations.

The principle method used to determine CO_2 movement in petroleum reservoirs has been production well compositional analysis. In a few cases, mostly pilot tests, observation wells have been used to detect CO_2 movement and/or saturation changes using logging tools. Production data will not be available in strictly storage projects and observation wells would be significant expenditure and the observations could well be deceptive due to direction permeability, fracture networks, or other heterogeneities. In one CO_2 injection pilot, no CO_2 was detected at a producer while CO_2 was produced in a well over one mile further away in direct line from the injector. This was a reservoir that was not thought to have a fracture system that contributed to fluid flow.

Being used and considered for widespread monitoring are seismic methods that include but are not limited to cross well tomography, 3- & 4-D seismic, and micro-seismic. These have each been used with varying levels of success. In one case cross well tomography was used to successfully track and predict arrival of CO_2 to the producer. One problem reported was that respondents were not sure if the signal changes that were being tracked were activated by fluid differences or formation deformation. If the formation deformation tracked the fluid movement, it will not be of consequence, but if the deformations precede or proceed a significant distance from the fluid movement, then they became important. For example, the injected fluid can compress the surrounding fluid and send a pressure pulse or displaced fluid movement that might be misinterpreted as the leading edge of the injected fluid.

In another case seismic changes were noted in a formation 800 feet above the injection zone. It was feared that CO_2 was leaking 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 at this time. Thus, more work is required in this area before monitoring seismic changes can be considered a reliable tool.

VI. Losses out of zone

We wanted to know how successful producers thought they were in delivering CO_2 where it was intended. Most thought they were keeping the CO_2 in the formation and could account for fluid within engineering accuracies. Several have noted that CO_2 was going into zones that are in communication with the injection zone. As CO_2 is less dense, it was expected to stay at the top of the reservoir, but several found CO_2 migrating into water or residual oil zones below the zone of interest. This could be caused by several phenomena. One is diffusion, which normally has a low rate compared to fluid flow rates of injected fluids. Diffusion will be a parameter that must be noted in long-term sequestration. Another cause is the increased density of the crude oils and brines that result in most reservoir conditions with dissolved CO_2. These heavier fluids will create convection currents pulling fluid into deeper areas of the reservoir. Both of these phenomena could be used if properly understood to increase sequestration amount and duration.

Unexpected fractures, thief zones, and loss out of the flanks of the structure have been suspected as culprits of CO_2 loss. Often the ratio of injection versus production fluid has not been tracked as closely as it could. Water production is often not tracked as closely as oil or CO_2; thus the fluid in-out ratio may not be as accurate as will be required in the future to assure minimal fluid is being lost out of the intended zone. Technology to achieve the required precision probably exists, but remembering that in-out fluid ratios do not take into account dissolution and precipitation of CO_2 in the reservoir. The work in progress for subsurface monitoring is essential.

VII. What has gone well?

We asked what had gone well in the project. The purpose of this question was to provide some idea of what petroleum producers look for to consider a project a successful CO_2 flood. It is of interest to note that the response to what has not gone well had almost twice as many responses (see the next section). It was not a surprise that the principal concern was significant, timely oil response. Most of the modeling and engineering studies centered on optimizing and predicting oil response. The fact that respondents mentioned injectivity in a couple cases confirms this as a problem that concerns many projects and that is being monitored.

Table 6. What has Gone Well

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

VIII. 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 important parameters to consider when designing a project. Again, oil response time and magnitude is premier among concerns and was disappointing in a number of floods. Second, low injectivity that can be a cause of low or late oil response, thus a slow process rate for the reservoir, was a concern. Third, problems with early and high CO_2 production can be a problem with gas processing facilities. Scaling/deposition had a number of responses. This could also be occurring within the reservoir and is a subject being studied by other teams under the CCP and also as part of a PRRC DOE contract. Deposition in the reservoir can result in increased CO_2 retention as well as modified injectivity.

Table 7. What has Not Gone Well

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

IX. Attempted remediation and success rates

Methods employed to remedy problems mentioned in the previous sections are listed in Table 8. Most of the remediation methods were used to reduce CO_2 production, to improve on processing of the reservoir, or increase injectivity. It was interesting to look at success rates. In using WAG management to control/improve (decrease) CO_2 production while maintaining or increasing oil production, the results have been generally good. Control of conformance with gels, foams, or squeeze jobs has been fair, but with a concern for expense. Attempts to improve injectivity have meet with temporary or no success.

Table 8. Remediation

Responses	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

X. 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. They do not commence with WAG. The initial CO_2 slug is often targeted to be 10-30% PV. The intent is usually to switching from a CO_2 slug to WAG after CO_2 breakthrough and gas production control is required. In several cases the initial intent was abandoned when another phase of the project was ready to start CO_2 injection and economics dictated putting the previous phase on WAG and using the freed CO_2 for the next phase versus increasing CO_2 purchase. The large CO_2 slug has the advantage of minimizing the time of the first significant oil response occurs as well as reducing the impact of decreases in injectivity in the brine half-cycle by delaying brine injection as long as practical as well as delaying possible decreases in CO_2 injectivity in subsequent CO_2 half-cycles. Again reservoir characterization was near the top of concerns by a number of individuals.

Table 9. Future Improvements

Responses	Number
Economic: Lower CO_2 cost, 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 & infill wells, patience, lower reservoir pressure, stimulate early	5

XI. Mysteries of the system.

Reported in this section are items that project engineers felt were not well understood. These are items that, if better understood, would improve the project. This could mean improved profits and in some cases a modification of the project area. Thirty-one of the responses (~90% of the total) desired better understanding of reservoir processing rates, reservoir characterization, and injectivity, which all concern the interconnection of understanding the reservoir, fluid flow, and fluid-reservoir interactions.

Table 10. Mysteries

Responses	Number
Processing rate	12
Reservoir Characterization	12
Injectivity	7
Scaling, asphaltenes, conformance, equipment	4

XII.Research focus

Improving sweep and productivity/injectivity were the two major areas of concern for future or continued study. Again, these responses are from individuals that are concerned about improving oil recovery, specifically, profit. The first three items are relevant to storage or sequestering CO_2. First, an understanding on how the injected fluid processes the reservoir is critical and this is interconnected to the second response of injection and production rates. The third, even though it is important for IOR to monitor CO_2, the ability to monitor the CO_2 plum is essential to understanding and predicting long-term CO_2 storage.

Table 11. Research Focus

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

XIII.Reservoir volumes.

The 86 reservoirs listed below with their estimated total reservoir volumes represent a total volume of about 6.14 x 10^{10} barrels (3.45×10^{11} ft^3 or 0.98×10^{10} m^3). Assuming a CO_2 density of 0.8 g/cc (~50 lbs/ft^3) under reservoir conditions, this is about 0.86×10^{10} tons of CO_2. This assumes the ability to replace 100% of the fluid volume with CO_2, which is not practical. If a conservative displacement efficiency and CO_2 retention of 11-12% of the pore volume is assumed, the result would be about 1×10^9 tons of CO_2 stored in these reservoirs. This would be about thirty years of injection at the present injection rate in this region.

Table 12. Volumes of the Studied Reservoirs

CO_2 Project	Total Reservoir Volume	Hydrocarbon Volume	Stock Tank Volume
	Volumes × 10^6 Barrels		
Adair San Andres	292	190	169
Anton Irish	848	619	516
Bennett Ranch	900	195	412
Brahaney	25	20	17
Brahaney Plains	25	17	14
Cedar Lake	309	185	154
Central Vacuum	82	57	45
Cogdell	101	71	59
Cordona Lake	240	168	140
Dollarhide (Devonian)	248	174	145
Dollarhide (Clearfork "AB")	311	225	136
East Ford	70	49	41
East Huntley	42	30	25
East Penwell (SA)	21	15	12
East Vacuum	453	381	296
El Mar	507	355	296
Ford Geraldine	167	125	98
Garza	126	88	73
GMK South	44	28	26
Goldsmith	30	24	17
Hanford	48	34	29
Hanford East	14	10	8
Hansford Marmaton	56	32	24
Jess Burnes	8	5	5
Kingdom Abo	124	99	92
Leamex	15	10	9
Levelland	1293	991	805
Levelland	166	127	104
Loco Hills	91	73	48
Mabee	582	471	430
Maljamar Pilot & Field	280	224	179
McElroy	144	101	88
McElroy	6751	4725	4116
Means (San Andres)	564	400	385
Mid Cross-Devonian	93	74	59
North Cowden	11	8	6
North Cross (Crossett)	170	111	56
North Dollarhide	109	87	55
North El Mar	155	124	103

CO_2 Project	Total Reservoir Volume	Hydrocarbon Volume	Stock Tank Volume
	Volumes × 10^6 Barrels		
North Farnsworth	22	17	15
North Hansford Cherokee	85	68	57
North Hobbs	388	310	259
North Van Rueder	50	40	33
North Ward Estes	3754	1877	1564
Philmex	20	12	10
Ranger Lake	25	20	17
Rankin	6	5	4
Reeves	396	317	264
Reinecke	29	23	19
Robertson (Central and N.)	135	95	75
Russell	374	299	249
Sable	27	22	18
SACROC	5002	3907	2604
Salt Creek	1117	994	829
Seminole -Main Pay	1725	1449	1050
Seminole -ROZ Phase 1	92	29	24
Sharon Ridge	857	662	432
Slaughter Alex Estate	39	31	26
Slaughter Central Mallet	398	366	298
Slaughter Estate & Pilot	62	50	41
Slaughter Frazier	117	88	72
Slaughter HT Boyd Lease	342	304	248
Slaughter (started June-89)	22	20	16
Slaughter (started May-85)	607	476	399
Slaughter Sundown	542	507	307
South Cowden	22	18	15
South Cowden (Emmons)	98	78	65
South Cross (Crossett)	98	68	57
South Huntley	74	44	37
South Welch & Pilots	367	2200	184
Spraberry Trend	16697	12522	10435
State 35 Unit (Hale Mable)	32	27	21
T-Star	27	20	17
Twofreds-East & West	134	76	68
University Waddell	43	30	25
VGSAU	82	57	45
Wasson	55	40	32
Wasson Cornell	257	218	168
Wasson Denver	3552	3126	2383
Wasson ODC & Pilot	1089	872	726
Wasson South	443	324	259

CO_2 Project	Total Reservoir Volume	Hydrocarbon Volume	Stock Tank Volume
	Volumes × 10^6 Barrels		
Wasson Willard & Pilot	1046	937	639
Wellman	208	166	128
West Brahaney	16	10	9
West Welch	30	18	15
Yates	5326	4261	3551
TOTAL	**61445**	**48025**	**37101**

CONCLUSIONS

1. There is significant experience and knowledge in the industry to separate, compress, transport, inject, and process the quantities of CO_2 that are envisioned for CO_2 sequestration/storage. Improvement is always possible and will be made as the volumes increase. What is required is the incentive to sequester CO_2.
2. An area that is in its development infancy is the monitoring and verification of CO_2 flow in geological formations.
3. Experience has shown that CO_2 goes where expected unless the reservoir characterization is not well understood and/or not honored if known. In some cases, phenomena have been noted during waterflood, but not included when simulating the CO_2 process. Also the phase properties of CO_2 must be honored.
4. CO_2 does what is expected: mobilizes oil, dissolves in brine, promotes dissolution of carbonates, and saturated brine will become supersaturated when the pressure dropped as it advances through the reservoir and precipitate is expected. However, the kinetics under many reservoir conditions requires further study.
5. In the short geological time frame that CO_2 has been actively injected into geological formations, seals are retaining the CO_2 in place. Proven seals, to date, perform as expected.
6. Safety is an item that was not mentioned in the discussions. I have worked for twenty-two years in the area of CO_2 production, transportation, and injection into geological formations of significant quantities of CO_2 without ever hearing of 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.

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Appendix A. Literature Review

List of OGJ Journal Articles and SPE abbreviation

SPE: Society of Petroleum Engineers Article #
2002 OGJ: Oil & Gas Journal-2002 Worldwide EOR Survey (Apr. 15, 2002)
2000 OGJ: Oil & Gas Journal-2000 Worldwide EOR Survey (Mar. 20, 2000)
1998 OGJ: Oil & Gas Journal-1998 Worldwide EOR Survey (Apr. 20, 1998)
1996 OGJ: Oil & Gas Journal-1996 Worldwide EOR Survey (Apr. 15, 1996)
1994 OGJ: Oil & Gas Journal-1994 Worldwide EOR Survey (Sept. 26, 1994)
1992 OGJ: Oil & Gas Journal-1992 Worldwide EOR Survey (Apr. 20, 1992)
1990 OGJ: Oil & Gas Journal-1990 Worldwide EOR Survey (Apr. 20, 1992)
1988 OGJ: Oil & Gas Journal-1988 Worldwide EOR Survey (Apr. 18, 1988)
1986 OGJ: Oil & Gas Journal-1986 Worldwide EOR Survey (Apr. 14, 1986)
1984 OGJ: Oil & Gas Journal-1984 Worldwide EOR Survey (Apr. 2, 1984)
1982 OGJ: Oil & Gas Journal-1982 Worldwide EOR Survey (Apr. 5, 1982)
1980 OGJ: Oil & Gas Journal-1980 Worldwide EOR Survey (Mar. 31, 1980)
1978 OGJ: Oil & Gas Journal-1978 Worldwide EOR Survey (Mar. 27, 1978)

List of SPE articles by state, project, SPE #, and Title

State	***Unit***	***SPE #***	***Title***
NM	Central Vacuum	63134	Dynamic Reservoir Characterization at Central Vacuum Unit
		60890	Time-Lapse Seismic Monitoring and Dynamic Reservoir Characterization, Central Vacuum Unit, Lea County, New Mexico
		56689	Tracking Miscible Processes in the Subsurface Utilizing Time Lapse Shear Wave Seismic Data
		49292	Time-Lapse Seismic Monitoring and Dynamic Reservoir Characterization, Central Vacuum Unit, Lea County, New Mexico
		38694	Dynamic Reservoir Characterization of a CO_2 Huff'n'Puff, Central Vacuum Unit, Lea County, New Mexico
		27656	Potential of the Cyclic CO_2 Process in a Waterflooded, Light Oil, Shallow Shelf Carbonate Reservoir
		19666	The Effects of Waterflooding on Reservoir Properties and Producing Operations: Applications for Geochemical Modeling
	East Vacuum	66569	Feasibility of Monitoring CO_2 Sequestration in a Mature Oil Field Time-Lapse Seismic Analysis
		53714	Management of Water Alternating Gas (WAG) Injection Projects
		39793	History Matching and Modeling the CO_2-Foam Pilot Test at EVGSAU
		36710	East Vacuum Grayburg San Andres Unit CO_2 Flood Ten Year Performance Review: Evolution of a Reservoir Management Strategy and Results of WAG Optimization
		27798	CO_2 Foam Field Verification Pilot Test at EVGSAU: Phase IIIC —Reservoir Characterization and Response to Foam Injection
		27786	CO_2 Foam Field Verification Pilot Test at EVGSAU: Phase IIIB —Project Operations and Performance Review
		27785	CO_2 Foam Field Verification Pilot Test at EVGSAU: Phase IIIA

State	Unit	SPE #	Title
			—Surfactant Performance Characterization and Quality Assurance
		27675	Laboratory Flow Tests Used To Determine Reservoir Simulator Foam Parameters for EVGSAU CO_2 Foam Pilot
		26478	Reservoir Description by Inverse Modeling: Application to EVGSAU Field
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		24928	Update of Industry Experience With CO_2 Injection
		24642	CO_2 Foam Field Verification Pilot Test at EVGSAU: Phase II -Foam Injection Design and Operating Plan
		24176	CO_2-Foam Field Verification Pilot Test at EVGSAU Injection Project Phase I: Project Planning and Initial Results
		19666	The Effects of Waterflooding on Reservoir Properties and Producing Operations: Applications for Geochemical Modeling
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		16721	East Vacuum Grayburg-San Andres Unit CO_2 Injection Project: Development and Results to Date
	State 35 Unit (Hale Mable)	16722	Development and Results of the Hale/Mable Leases Cooperative Polymer EOR Injection Project, Vacuum (Grayburg-San Andres) Field, Lea County, New Mexico
	Leamex	NA	No Article Found
	Loco Hills	339	Successful Pilot Predicts Bright Future for Loco Hills Water Flood, New Mexico
	Maljamar (Conoco)	27784	Effect of Pressure on CO_2 Foam Displacements: A Micromodel Visualization Study
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		24111	Prediction of CO_2/Crude Oil Phase Behavior Using Supercritical Fluid Chromatography
		20109	Automated CO_2 Injection Control and Well Test Monitoring System
		18977	Summary Results of CO_2 EOR Field Tests, 197_2-1987
		18976	Innovative Techniques for Converting Old Waterflood Injectors to State-of-the-Art CO_2 Injectors
		17371	Tracer Surveys To Identify Channels for Remedial Work Prior to CO_2 Injection at MCA Unit, New Mexico
		17323	History Match of the Maljamar CO_2 Pilot Performance
		15400	Effect of an Aqueous Phase on CO_2/Tetradecane and CO_2/Maljamar, Crude-Oil Systems
		15079	Solubility and Extraction in Multiple-Contact Miscible Displacements: Comparison of N_2 and CO_2 Flow Visualization Experiments
		14940	The Maljamar CO_2 Pilot: Review and Results
		14897	Diffusion of CO_2 at Reservoir Conditions: Models and Measurements
		14149	Effect of Oil Composition on Minimum Miscibility Pressure-Part 1: Solubility of Hydrocarbons in Dense CO_2
		14148	Four-Phase Flash Equilibrium Calculations Using the Peng-Robinson Equation of State and a Mixing Rule for Asymmetric Systems
		14147	Experimental Investigation of the Interaction of Phase Behavior With Microscopic Heterogeneity in a CO_2 Flood
		13142	Use of Well Logs To Characterize Fluid Flow in the Maljamar CO_2 Pilot

State	*Unit*	*SPE #*	*Title*
		12666	First Results From the Maljamar Carbon Dioxide Pilot
		12600	Development and Status of the Maljamar CO_2 Pilot
		11337	Formation Damage Potential from Carbon Dioxide-Crude Oil Interaction
	Maljamar (Phillips)	26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
	VGSAU	NA	No articles found, project will start January 2002
TX	Adair San Andres	19783	An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
		16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
	Anton Irish	11930	Case History of Large-Volume Fracture Stimulations in a West Texas Waterflood
	Bennett	35188	Design and Implementation of a Grass-Roots CO_2 Project for the Bennett Ranch Unit
		18224	Carbonate Stimulation Optimization Using Hydraulic Fracturing Field Testing
		13095	Improved Formation Evaluation From Pressure and Conventional Cores Taken With Stable Foam-Bennett Ranch Unit (Wasson Field)
		9798	San Andres Reservoir Pressure Coring Project For Enhanced Oil Recovery Evaluation, Bennett Ranch Unit, Wasson Field, West Texas
		16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
		15571	Compositional Simulation of the Block 31 Field and Surface Facilities
		13669	Analysis and Correlation of Nitrogen and Lean-Gas Miscibility Pressure
	Brahaney Plains	NA	No articles found
	Cedar Lake	NA	No articles found
	Clearfork (and AB Unit)	27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
		25853	An Integrated Approach To Characterize Low-Permeability Reservoir Connectivity for Optimal Waterflood Infill Drilling
		19783	An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
		12017	Waterflooding the Grayburg Formation on the J.L. Johnson AB Lease: Experience in the Johnson Field
	Cogdell	NA	No articles found
	Cordona Lake	26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		24928	Update of Industry Experience With CO_2 Injection
	Cowden (North and South)	NA	Click North Cowden or South Cowden
	Cross (North and South)	NA	Click North Cross or South Cross
	Dollarhide	39787	Find Grid CO Injection Process Simulation for Dollarhide Devonian Reservoir
		27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields

State	***Unit***	***SPE #***	***Title***
		20098	Numerical Evaluation of Single-Slug, WAG, and Hybrid CO_2 Injection Processes, Dollarhide Devonian Unit, Andrews County, Texas
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		17294	State of the Art Installation of CO_2 Injection Equipment: A Case Study
		17277	Evaluation and Implementation Of CO_2 Injection at the Dollarhide Devonian Unit
			Click also North Dollarhide
	East Ford	NA	No articles found
	East Penwell	NA	No articles found
	El Mar	NA	No articles found
	Ford Geraldine	39794	Compositional Simulations of a CO Flood in Ford Geraldine Unit, Texas
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		24928	Update of Industry Experience With CO_2 Injection
		20227	A Full-Field Numerical Modeling Study for the Ford Geraldine Unit CO_2 Flood
		20118	The Ford Geraldine Unit CO_2 Flood- Update 1990
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		17278	The Ford Geraldine Unit CO_2 Flood: Operating History
		12197	CO_2 Flood: Design and Initial Operations, Ford Geraldine (Delaware Sand) Unit
		6883	Pecos River Water Treatment for Water Injection
		6383	Field Study - Ford Geraldine (Delaware Sand) Unit
	Garza	NA	No relevant articles found
	GMK South	19046	Utilization of a Black-Oil Simulator as a Monitor of Waterflood Operations in a San Andres Reservoir
	Goldsmith	48945	Goldsmith San Andres Unit CO_2 Pilot - Design, Implementation, and Early Performance
		39514	Use, Quantification and Learnings From a Vertical Pulse Test Conducted for Barrier
		20137	Evaluation of Alternating Phase Fracture Acidizing Treatment Using Measured Bottomhole Pressure
		16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
		9719	Response of North Cowden and Goldsmith Crudes to Carbon Dioxide Slugs Pushed by Nitrogen
		1888	Gas Turbine Driven Centrifugal Pumps for High Pressure Water Injection
	Hanford	20229	A Case History of the Hanford San Andres Miscible CO_2 Project
	Hanford East	NA	No articles found
	Hansford Cherokee, North	NA	Click North Hansford Cherokee
	Hansford Marmaton	26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		17327	CO_2 Injection Increases Hansford Marmaton Production
	Huntley (South, East included)	27762	A Probabilistic Forecasting Method for the Huntley CO_2 Projects
	Jess Burnes	NA	No articles found
	Kingdom Abo	9720	Early Implementation of a Full-Scale Waterflood in the Abo Reef, Terry Co. TX. - A Case History
		9475	Early Implementation of a Full-Scale Waterflood in the Abo

State	*Unit*	*SPE #*	*Title*
			Reef, Terry Co., TX - A Case History
	Levelland	71496	Physical Effects of WAG Fluids on Carbonate Core Plugs
		25413	Application of a Three-Dimensional Hydraulic Fracturing Simulator for Design of Acid Fracturing Treatments
		23974	Analysis of Tertiary Injectivity of Carbon Dioxide
		16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
		16716	The Effects Of CO_2 Flooding on Wettability of West Texas Dolomitic Formations
		14308	Investigation of Unexpectedly Low Field-Observed Fluid Mobilities During Some CO_2 Tertiary Floods
		12148	Pilot Plant Performance of Triethanolamine for Bulk CO_2 Separation
		11121	Use of a Novel Liquid Gelling Agent for Acidizing in the Levelland Field
		9786	Utilization of Composition Observation Wells in a West Texas CO_2 Pilot Flood
		9785	Carbon Dioxide Displacement of a West Texas Reservoir Oil
		9764	Injection Well Workover Program in the Levelland Field: A Case History
		8831	Design and Implementation of a Levelland Unit CO_2 Tertiary Pilot
		8410	Design and Operation of the Levelland Unit CO_2 Injection Facility
		5826	Enriched-Gas Miscible Flooding: A Case History of the Levelland Unit Secondary Miscible Project
	Mabee	71496	Physical Effects of WAG Fluids on Carbonate Core Plugs
		24163	Interpretation of a CO_2 WAG Injectivity Test in the San Andres Formation Using a Compositional Simulator
		22653	A Laboratory and Field Injectivity Study: CO_2 WAG in the San Andres Formation of West Texas
	Mallet	70068	Conformance Water-Management Team Developments and Solutions on Projects in the Permian Basin
		36711	From Simulator to Field Management: Optimum WAG Application in a West Texas CO_2 Flood - A Case History
		20377	Optimization of Waterflood Performance and CO_2-Flood Design Using a Modeling Approach, Mallet Unit, Slaughter Field
		16831	Carbonated Waterflood Implementation and Its Impact on Material Performance in a Pilot Project
		16830	CO_2 Injection and Production Field Facilities Design Evaluation and Considerations
		12015	Comprehensive Geological and Reservoir Engineering Evaluation of the Lower San Andres Dolomite Reservoir, Mallet Lease, Slaughter Field, Hockley County, Texas
	McElroy	59528	Injection-side Application of MARCIT Polymer Gel Improves Waterflood Sweep Efficiency, Decreases Water-Oil Ratio, and Enhances Oil Recovery in the McElroy Field, Upton County, Texas
		38910	Modeling of Waterflood in a Vuggy Carbonate Reservoir
		24873	Waterflood Improvement in the Permian Basin: Impact of In-Situ Stress Evaluations
		24184	Phase Behavior Modeling Techniques for Low-Temperature CO_2 Applied to McElroy and North Ward Estes Projects

State	*Unit*	*SPE #*	*Title*
		20120	Waterflood Pattern Realignment at the McElroy Field: Section 205 Case History
		20105	In-Situ Stress Evaluation in the McElroy Field, West Texas
		853	Pilot Water Flooding in a Dolomite Reservoir, The McElroy Field
	Mead Strawn	17134	Evolution of the Carbon Dioxide Flooding Processes
		3103	Carbon Dioxide Test at the Mead-Strawn Field
	Means (San Andres)	27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		24928	Update of Industry Experience With CO_2 Injection
		24111	Prediction of CO_2/Crude Oil Phase Behavior Using Supercritical Fluid Chromatography
		19783	An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		17349	Review of the Means San Andres Unit CO_2 Tertiary Project
		16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
		15037	An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units
		11987	Design and Operation of a CO_2 Tertiary Pilot: Means San Andres Unit
		11023	Infill Drilling To Increase Reserves-Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois
		6739	Improved Techniques for Evaluating Carbonate Waterfloods in West Texas
		3301	Evaluation and Modification of the Means San Andres Unit Waterflood
	Mid Cross-Devonian	NA	No articles found
	North Cowden	28385	Integrated Reservoir Characterization: Beyond Tomography
		27671	Hydrocyclone Separation: A Preferred Means of Water Separation and Handling in Oilfield Production
		25655	Geostatistical Application for Exploration and Development: Porosity Estimation From 3-D Seismic Data Calibrated to Well Data
		16716	The Effects Of CO_2 Flooding on Wettability of West Texas Dolomitic Formations
		11165	Preliminary Findings From a Study To Perform Automated Metering and Control of Carbon Dioxide Injection With a Liquid Turbine Meter
		9719	Response of North Cowden and Goldsmith Crudes to Carbon Dioxide Slugs Pushed by Nitrogen
		9364	Solar Powered Injection Controller Utilizing Bottom Hole Pressure Sensing Device
		NA	Click also South Cowden or return to Cowden (North and South)
	North Cross (Crossett)	26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		24210	North Cross (Devonian) Unit CO_2 Flood: Status Report
		24115	Role of Three-Hydrocarbon-Phase Flow in a Gas Displacement

State	*Unit*	*SPE #*	*Title*
			Process
		23974	Analysis of Tertiary Injectivity of Carbon Dioxide
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		17134	Evolution of the Carbon Dioxide Flooding Processes
		6390	North Cross (Devonian) Unit CO_2 Flood – Review of Flood Performance and Numerical Simulation Model
		4737	The Use of Numerical Simulation To Design a Carbon Dioxide Miscible Displacement Project
		NA	Click also South Cross, or return to Cross (North and South)
	North Dollarhide	27678	North Dollarhide (Devonian) Unit: Reservoir Characterization and CO_2 Feasibility Study
		NA	Click also Dollarhide
	North Farnsworth	26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
	North Hansford Cherokee	NA	No articles found
		NA	Go back to Hansford Cherokee, North
	North Van Rueder	NA	No articles found
		NA	Go to Van Rueder, North
	North Ward Estes	71496	Physical Effects of WAG Fluids on Carbonate Core Plugs
		30729	An Overview of the North Ward Estes CO_2 Flood
		24643	CO_2 Foam Field Trial at North Ward-Estes
		24184	Phase Behavior Modeling Techniques for Low-Temperature CO_2 Applied to McElroy and North Ward Estes Projects
		20702	Converting Wells in a Mature West Texas Field for CO_2 Injection
		20138	Reservoir Management: A Synergistic Approach
		20099	Converting Wells in a Mature West Texas Field for CO2 Injection
		19654	Design of a Major CO_2 Flood, North Ward Estes Field, Ward County, Texas
		17281	Optimization of Fracture Stimulation Within the North Ward Estes Field
		9711	Fireflooding a High-Gravity Crude in a Watered-Out West Texas Sandstone
		5831	Alkaline Waterflooding: Design and Implementation of a Field Pilot
		1147	Reinjection of Large Volumes of Produced Water in Secondary Operations
		NA	Go to Ward Estes, North
	Rankin	NA	No articles found
	Reeves	NA	No articles found
	Reinecke	59717	A Pulsed Neutron Analysis Model Carbon Dioxide Floods: Application to the Reinecke Field, West Texas
		56882	Use of Full-Field Simulation to Design a Miscible CO_2 Flood
		56524	Spatial Distribution of Oil and Water in Horizontal Pipe Flow
	Robertson	70034	Improved Permeability Estimates in Carbonate Reservoirs Using Electrofacies Characterization: A Case Study of the North Robertson Unit, West Texas
		68801	Neural-Network Approach To Predict Well Performance Using Available Field Data
		62557	Swept Volume Calculations and Ranking of Geostatistical Reservoir Models Using Streamline Simulation
		59715	Tiltmeter Hydraulic Fracture Mapping in the North Robertson

State	*Unit*	*SPE #*	*Title*
			Field, West Texas
		35433	Flow Unit Characterization of a Shallow Shelf Carbonate Reservoir: North Robertson Unit, West Texas
		27668	Improved Reservoir Management With Water Quality Enhancement at the North Robertson Unit
		19783	An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
		16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
		15568	Quantitative Analysis of Infill Performance: Robertson Clearfork Unit
		15037	An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units
		11023	Infill Drilling To Increase Reserves- Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois
		6739	Improved Techniques for Evaluating Carbonate Waterfloods in West Texas
		4064	Efficient Removal of Oxygen in a Waterflood By Vacuum Deaeration
	Russell	NA	No relevant articles found
	Sable	NA	No articles found
	SACROC (includes Kelly Snyder)	56882	Use of Full-Field Simulation to Design a Miscible CO_2 Flood (also in Reinecke)
		35359	SACROC Unit Carbon Dioxide Flood -- Multidisciplinary Team Improves Reservoir Management and Decreases Operating Costs
		27762	A Probabilistic Forecasting Method for the Huntley CO_2 Projects
		27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		24928	Update of Industry Experience With CO_2 Injection
		19023	A New Approach to SACROC Injection Well Testing
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		17321	Definitive CO_2 Flooding Response in the SACROC Unit
		15916	Surface Processing of Carbon Dioxide in EOR Projects
		14923	Phase Equilibria in the SACROC Oil/CO_2, System
		12645	A Laboratory Study of CO_2 Foam Properties and Displacement Mechanism
		11162	Ten Years of Handling CO_2 for SACROC Unit
		7091	Performance Review of a Large-Scale CO_2-WAG Enhanced Recovery Project, SACROC Unit Kelly-Snyder Field
		7090	SACROC Tertiary CO_2 Pilot Project
		6391	Corrosion and Operational Problems, CO_2 Project, Sacroc Unit
		5536	Reservoir Description by Simulation at SACROC - A Case History
		5052	Compressibility Factors for CO_2-Methane Mixtures
		4804	Design and Operation of a Supercritical CO_2 Pipeline-Compression System SACROC Unit, Scurry County, Texas
		4667	Effect of Supercritical Carbon Dioxide (CO_2) on Construction Materials
		4083	Evaluation and Design of a CO_2 Miscible Flood Project-

State	***Unit***	***SPE #***	***Title***
			SACROC Unit, Kelly-Snyder Field
		1147	Reinjection of Large Volumes of Produced Water in Secondary Operations
		933	Desorption of Oxygen From Water Using Natural Gas for Countercurrent Stripping
	Salt Creek	56882	Use of Full-Field Simulation to Design a Miscible CO_2 Flood
		39667	Permeability Predictions in Carbonate Reservoirs Using Optimal Non-parametric
		23958	Case Histories of Step Rate Tests in Injection Wells
	Seminole (includes West, main pay and ROZ)	71496	Physical Effects of WAG Fluids on Carbonate Core Plugs
		59691	San Andres and Grayburg Imbibition Reservoirs
		36515	Integrated Reservoir Characterization Study of a Carbonate Ramp Reservoir: Seminole San Andres Unit, Gaines County, Texas
		27715	Critical Scales, Upscaling, and Modeling of Shallow-Water Carbonate Reservoirs
		27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		24928	Update of Industry Experience With CO_2 Injection
		24702	Defining Flow Units in Dolomitized Carbonate-Ramp Reservoirs
		19783	An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
		17290	New Fiberglass Liner Completion Technique Salvages Old Injection Wells for Use as WAG Injection Wells
		16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
		10022	The Role of Numerical Simulation in Reservoir Management of a West Texas Carbonate Reservoir
		8274	Improved Reservoir Characterization: A Key to Future Reservoir Management for the West Seminole San Andres Unit
		7796	Sheep Mountain CO_2 Production Facilities - A Conceptual Design
		6738	Reservoir Data Pays Off: West Seminole San Andres Unit, Gaines County, Texas
		4064	Efficient Removal of Oxygen in a Waterflood By Vacuum Deaeration
	Sharon Ridge	65029	Mineral Scale Control in a CO_2 Flooded Oilfield
		56882	Use of Full-Field Simulation to Design a Miscible CO_2 Flood
		39629	Use of Full-Field Simulation to Design a Miscible CO_2 Flood
		3443	Performance of Sharon Ridge Canyon Unit with Water Injection
		37	Pressure Maintenance Operations in the Sharon Ridge Canyon Unit, Scurry County, Tex.
	Slaughter	NA	Click Slaughter Field for articles on Slaughter
	Slaughter (Central Mallet)	NA	Click Mallet for articles on Mallet Unit in Slaughter
		NA	Click Slaughter Field to view articles about Slaughter
	Slaughter Estate	27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate

State	*Unit*	*SPE #*	*Title*
			Reservoirs
		26624	Reservoir Management in Tertiary CO_2 Floods
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		23974	Analysis of Tertiary Injectivity of Carbon Dioxide
		19375	Slaughter Estate Unit CO_2 Flood: Comparison Between Pilot and Field-Scale Performance
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		16830	CO_2 Injection and Production Field Facilities Design Evaluation and Considerations
		16716	The Effects Of CO_2 Flooding on Wettability of West Texas Dolomitic Formations
		10727	Slaughter Estate Unit Tertiary Miscible Gas Pilot Reservoir Description
		9796	Slaughter Estate Unit Tertiary Pilot Performance
		8830	Slaughter Estate Unit CO_2 Pilot - Surface and Downhole Equipment Construction and Operation in the Presence of H_2S
	Slaughter Field	71496	Physical Effects of WAG Fluids on Carbonate Core Plugs
		70068	Conformance Water-Management Team Developments and Solutions on Projects in the Permian Basin
		27648	Normalization of Cased-Hole Neutron Logs, Slaughter Field, Cochran and Hockley Counties, Texas
		27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
		26335	Coiled-Tubing Sidetrack: Slaughter Field Case History
		24928	Update of Industry Experience With CO_2 Injection
		20377	Optimization of Waterflood Performance and CO_2-Flood Design Using a Modeling Approach, Mallet Unit, Slaughter Field
		20115	Reactivity of San Andres Dolomite
		19375	Slaughter Estate Unit CO_2 Flood: Comparison Between Pilot and Field-Scale Performance
		16831	Carbonated Waterflood Implementation and Its Impact on Material Performance in a Pilot Project
		14308	Investigation of Unexpectedly Low Field-Observed Fluid Mobilities During Some CO2 Tertiary Floods
		14288	A CO_2 Injection Measurement and Control System
		12015	Comprehensive Geological and Reservoir Engineering Evaluation of the Lower San Andres Dolomite Reservoir, Mallet Lease, Slaughter Field, Hockley County, Texas
		7570	Use of Fine Salt as a Fluid Loss Material in Acid Fracturing Stimulation Treatments
		4070	A Modeling Approach for Optimizing Waterflood Performance, Slaughter Field Chickenwire Pattern
		1576	Computer Processing of Log Data Improves Production In Chaveroo Field
		341	Small Propane Slug Proving Success in Slaughter Field Lease
	Slaughter Frazier	16830	CO_2 Injection and Production Field Facilities Design Evaluation and Considerations
	Slaughter Sundown	49168	Simulation of a CO_2 Flood in the Slaughter Field with Geostatistical Reservoir Characterization
		35410	Improved CO_2 Flood Predictions Using 3D Geologic Description and Simulation on the Sundown Slaughter Unit
		30742	Horizontal Well Applications in a Miscible CO_2 Flood,

State	*Unit*	*SPE #*	*Title*
			Sundown Slaughter Unit, Hockley County, Texas
	South Cowden	59691	San Andres and Grayburg Imbibition Reservoirs
		56609	Use of Sacrificial Agents in CO_2 Foam Flooding Application
		39666	Incorporating Seismic Attribute Porosity into a Flow Model of the Grayburg Reservoir
		37470	The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO_2 WAG Horizontal Injection Wells
		37218	Laboratory Evaluation of Surfactants for CO_2-Foam Applications at the South Cowden Unit
		36650	Characterization of Diagenetically Altered Carbonate Reservoirs, South Cowden Grayburg Reservoir, West Texas
		35429	Determination of Relative Permeability and Trapped Gas Saturation for Predictions of WAG Performance in the South Cowden CO_2 Flood
		35222	An Integrated Study of the Grayburg/San Andres Reservoir, Foster and South Cowden Fields, Ector County, Texas
		28334	Innovative Approach to CO_2 Project Development Holds Promise for Improving CO_2 Flood Economics in Smaller Fields Nearing Abandonment
		27658	Proposal for an Integrated Study of the Grayburg/San Andres Reservoir, Foster and South Cowden Fields, Ector County, Texas
		27655	Design and Implementation of a CO_2 Flood Utilizing Advanced Reservoir Characterization and Horizontal Injection Wells in a Shallow Shelf Carbonate
			Click also North Cowden, or return to Cowden (North and South)
	South Cross (Crossett)	NA	No articles found
		NA	Click also North Cross, or return to Cross (North and South)
	South Welch	27676	CO_2 Operating Plan, South Welch Unit, Dawson County, Texas
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		12664	CO_2 Miscible Flooding Evaluation of the South Welch Unit, Welch San Andres Field
		NA	See also West Welch and Welch
	Spraberry Trend	10759	The Effect of Lateral Anisotrophy on Flood Pattern Dimensions and Orientation
		405	Large Scale Waterflood Performances Sprayberry Field, West Texas
	Twofreds	26614	Update Case History: Performance of the Twofreds Tertiary CO_2 Project
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		18977	Summary Results of CO_2 EOR Field Tests, 1972-1987
		14439	Performance of the Twofreds CO_2 Injection Project
		8382	Twofreds Field a Tertiary Oil Recovery Project
		1792	Pressure Maintenance by Water Injection In the Twofreds (Delaware) Field Unit
	University Waddell	NA	No articles found
	Van Rueder, North	NA	Go back to North Van Rueder
	Waddell	1146	Pressure Maintenance by Bottom-Water Injection in a Massive San Andres Dolomite Reservoir
	Ward Estes, North	NA	Go back to North Ward Estes

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	Wasson	71496	Physical Effects of WAG Fluids on Carbonate Core Plugs
		24185	CO_2 Miscible Flood Simulation Study, Roberts Unit, Wasson Field, Yoakum County, Texas
		24111	Prediction of CO_2/Crude Oil Phase Behavior Using Supercritical Fluid Chromatography
		23974	Analysis of Tertiary Injectivity of Carbon Dioxide
		19783	An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
		19666	The Effects of Waterflooding on Reservoir Properties and Producing Operations: Applications for Geochemical Modeling
		19596	Outcrop/Subsurface Comparisons of Heterogeneity in the San Andres Formation
		16716	The Effects Of CO_2 Flooding on Wettability of West Texas Dolomitic Formations
		15037	An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units
		14288	A CO_2 Injection Measurement and Control System
		13116	Effect of Phase Behavior on CO_2 Displacement Efficiency at Low Temperatures: Model Studies With an Equation of State
		11592	CO_2 Flooding: Its Time Has Come
		11125	Interpretation of Pressure-Composition Phase Diagrams for CO_2/Crude-Oil Systems
		10686	An Investigation of Phase Behavior-Macroscopic Bypassing Interaction in CO_2 Flooding
		8367	The Effect of Phase Behavior on CO_2-Flood Displacement Efficiency
		3570	Use of the SP Log in Waterflood Surveillance
		2472	Three Porosity Movable Oil Plot Vs Single Porosity Movable Oil Plot to Improve Completion Results in the Wasson Field
	Wasson Cornell	16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
		15037	An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units
		10292	CO_2 Flood Performance Evaluation for the Cornell Unit, Wasson San Andres Field
		9762	Success of a High-Friction Diverting Gel in Acid Stimulation of a Carbonate Reservoir - Cornell Unit, San Andres Field
	Wasson Denver	59548	Denver Unit Infill Drilling and Pattern Reconfiguration Program
		56549	Reservoir Characterization and Development Plan of the Wasson San Andres Denver Unit Gas Cap
		29116	Field-Scale CO_2 Flood Simulations and Their Impact on the Performance of the Wasson Denver Unit
		27674	The Denver Unit CO_2 Flood Transforms Former Waterflood Injectors Into Oil Producers
		27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
		26391	CO_2 EOR Economics for Small-to-Medium-Size Fields
		24928	Update of Industry Experience With CO_2 Injection
		24644	Quantitative CO_2 Flood Monitoring, Denver Unit, Wasson (San Andres) Field
		24157	Overview of Production Engineering Aspects of Operating the Denver Unit CO_2 Flood

State	*Unit*	*SPE #*	*Title*
		24156	Production Performance of the Wasson Denver Unit CO_2 Flood
		19783	An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
		19725	Analyzing the Flowing Performance of Oil Wells: Denver Unit CO_2 Flood
		19596	Outcrop/Subsurface Comparisons of Heterogeneity in the San Andres Formation
		18883	Equilibrium Acid Fracturing: A New Fracture Acidizing Technique for Carbonate Formations
		17335	Comparison of Laboratory- and Field-Observed CO_2 Tertiary Injectivity
		16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
		14308	Investigation of Unexpectedly Low Field-Observed Fluid Mobilities During Some CO_2 Tertiary Floods
		13132	Effect of CO_2 Flooding on Dolomite Reservoir Rock, Denver Unit, Wasson (San Andres) Field, TX
		8406	Production Technology Experience in a Large Carbonate Waterflood, Denver Unit, Wasson San Andres Field
		6385	Denver Unit 10-Acre Infill Pilot Test and Residual Oil Testing
	Wasson ODC	35402	Field Test of Foam to Reduce CO_2 Cycling
		27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
		17754	A Brief History of the Wasson EOR Project
		16830	CO_2 Injection and Production Field Facilities Design Evaluation and Considerations
	Wasson South	70063	South Wasson Clear Fork Reservoir Model: Outcrop to Subsurface via Rock-Fabric Method
		24160	Early CO_2 Flood Experience at the South Wasson Clearfork Unit
		19783	An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
	Wasson Willard	27642	A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
		24928	Update of Industry Experience With CO_2 Injection
		19783	An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
		16854	Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
		15037	An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units
		7051	A Method for Projecting Full-Scale Performance of CO_2 Flooding in the Willard Unit
		7050	Coring for In-Situ Saturations in the Willard Unit CO_2 Flood Mini-Test
		7049	Use of Time-Lapse Logging Techniques in Evaluating the Willard Unit CO_2 Flood Mini-Test
		6389	Case History: A Pressure Core Hole
		6388	A Review of the Willard (San Andres) Unit CO_2 Injection Project
	Welch	62588	Interwell Seismic for Reservoir Characterization and Monitoring

State	***Unit***	***SPE #***	***Title***
		39808	West Welch CO Flood Simulation with an Equation of State and Mixed Wettability
		35160	Characterization of Rock Types With Mixed Wettability Using Log and Core Data - DOE Project Welch Field, Dawson County, Texas
		27676	CO_2 Operating Plan, South Welch Unit, Dawson County, Texas
		12664	CO_2 Miscible Flooding Evaluation of the South Welch Unit, Welch San Andres Field
		39	History of the Welch Field San Andres Pilot Water Flood
		NA	See also South Welch and West Welch
	Wellman	48948	Wellman Unit CO_2 Flood: Reservoir Pressure Reduction and Flooding the Water/Oil
		22898	Reservoir Performance of a Gravity-Stable Vertical CO_2 Miscible Flood: Wolfcamp Reef Reservoir, Wellman Unit
		11129	Numerical Simulation of a Gravity Stable, Miscible CO_2 Injection Project in a West Texas Carbonate Reef
		10065	A Technique for Obtaining In-Situ Saturations of Underpressured Reservoirs
	West Brahaney	NA	No articles found
	West Welch	39809	Improving Flow Simulation Performance with a Seismic-Enhanced Geologic Model
		39808	West Welch CO Flood Simulation with an Equation of State and Mixed Wettability
		35160	Characterization of Rock Types With Mixed Wettability Using Log and Core Data - DOE Project Welch Field, Dawson County, Texas
		NA	See also South Welch and Welch

SPE Paper Abstracts Listed by State, Project, and SPE Number

NM-Central Vacuum (Click Central Vacuum to return to table)

(63134) Dynamic Reservoir Characterization at Central Vacuum Unit

Multicomponent, time-lapse seismology has great potential for monitoring production processes in reservoirs. The main reason is simply the presence of fluid-filled fractures. Shear waves (s-waves) are much more sensitive than compressional waves (p-waves) to the presence of fractures or microfractures and the fluid content within the fracture network. Fractures introduce seismic anisotropy into a reservoir, causing two shear modes (S1 and S2) to propagate with different velocities and therefore different arrival times. This phenomenon is referred to as s-wave splitting or birefringence, and is critical for estimating fracture density (see Martin and Davis, 1987). At Central Vacuum Unit (CVU), s-wave splitting is developing as an important key to monitoring production processes associated with carbon dioxide (CO_2) flooding. Fluid property changes associated with CO_2 flooding produce changes in the velocities of the split s-waves passing through the reservoir interval. Fluid properties change in response to CO_2 and oil becoming a miscible phase in the presence of in-situ fluids. S-wave splitting can also be used to identify areas of anomalous reservoir pressure. S-wave splitting and velocities are extremely sensitive to the local stress field because all rocks, especially carbonates, contain incipient networks of microfractures at a state of near-criticality (Zatsepin and Crampin, 1997).

S-wave splitting can assist in separating effective stress changes associated with abnormal fluid pressures from fluid property change. This conclusion is inferred by results of the CVU study. During the first phase, Phase-I of this study, a prominent s-wave splitting anomaly was detected to the south of a cyclic CO_2

injection well (CVU 97). It is believed that this anomaly corresponded to the tertiary flood bank that developed south of this temporary injection well (Figure 1a). Noticeable in the periphery to this anomaly are anisotropy anomalies of opposite sign related to offset wells that were used to contain the CO_2 bank through water injection. The sign change of s-wave anisotropy occurs because the relative velocities of the split s-waves reverse. In the case of the miscible CO_2-oil bank, the S2 velocity increased and S1 decreased, whereas, in the case of water injection, the effective stress causes S2 to decrease and S1 to increase. Similar effects were observed during the second phase, Phase-II of the monitoring study (Figure 1b). These results imply that s-wave anisotropy can be used to monitor secondary (water flooding) as well as tertiary (CO_2) methods in a spatial context beyond the wellbore. This dynamic reservoir characterization could provide the industry with the ability to be more proactive than reactive in the management of reservoirs.

(60890) Time-Lapse Seismic Monitoring and Dynamic Reservoir Characterization, Central Vacuum Unit, Lea County, New Mexico

This article presents the results of a multidisciplinary, four-dimensional (4D) (time-lapse), three-component (3C) (multicomponent) seismic study of a CO_2 injection project in vacuum field, New Mexico. The ability to sense bulk rock/fluid properties with 4D, 3C seismology enables characterization of the most important transport property of a reservoir, namely, permeability. Because of the high volume resolution of the 4D, 3C seismology, we can monitor the sweep efficiency of a production process to see if reserves are bypassed by channeling around lower permeability parts of the reservoir and the rate at which the channeling occurs. In doing so, we can change production processes to sweep the reservoir more efficiently.

(56689) Tracking Miscible Processes in the Subsurface Utilizing Time Lapse Shear Wave Seismic Data

The Reservoir Characterization Project (RCP) is an industry-sponsored consortium. Its mission is to develop and apply 3-D and 4-D (time-lapse), multi-component seismology and associated technologies to improve reservoir performance and hydrocarbon recovery while reducing environmental impact. Current research is focused on utilizing 4-D multi-component seismic to track a CO_2 injection project at the Central Vacuum Unit, Lea County, New Mexico. This field produces from the San Andres reservoir, a shallow shelf carbonate reservoir located on the Northwestern Shelf of the Permian Basin, Southeastern New Mexico. Included are detailed schematics of the seismic and geologic/reservoir simulation areas with the type, quantity, and location of the available data. This portion of the Central Vacuum Unit is in the area where the Lovington siltstone is present. The Lovington effectively separates the San Andres into two producing intervals.

A CO_2 Huff-n-Puff pilot project was performed in well CVU-97 at the Central Vacuum Field and the repeated 3-D, 3-C seismic surveys were performed from October 1995 to December 1995. The initial survey was acquired prior to CO_2 injection. The second survey was acquired during the "soak" period of the Huff-n-Puff process after fifty (50) million SCF of CO_2 had been injected into the well during a four (4) week period.

Interpretation of this time lapse seismic data showed an anomaly due south of the CVU-97 well in the vicinity of the observation well, CVU-200. The simulation results showed an increase in CO_2 concentration going in the same direction. Caution needs to be applied in the emphasis placed on these results due to the relatively small volume of CO_2 injected during the pilot program. However, the results demonstrate the potential of using shear seismic data in tracking miscible processes. It is also interesting that the simulation results indicate that the shear waves seem to be more sensitive to the change in fluid properties rather than pressure.

The staged implementation of the CO_2 injection program started in the spring of 1997. Injection started in the 4-D seismic area in April 1998. In November of 1997 a new base line of multi-component seismic data was acquired. The time-lapse seismic acquisition was performed in November of 1998. Interpretation of these results is still ongoing.

(49292) Time-Lapse Seismic Monitoring and Dynamic Reservoir Characterization, Central Vacuum Unit, Lea County, New Mexico

The Reservoir Characterization Project (RCP) is an industry sponsored consortium whose mission is to develop and apply 3-D and 4-D ("time-lapse"), 3-C seismology and associated technologies to improve reservoir performance and hydrocarbon recovery while reducing environmental impact. RCP Phase VI is the multidisciplinary, 4-D, 3-C study of a CO_2 injection project in Vacuum field, a shallow shelf carbonate reservoir located on the Northwestern Shelf of the Permian Basin of West Texas and Southeastern New Mexico.

The CO_2 "huff-n-puff" in well Texaco CVU-97 at Vacuum Field and the repeated 3-D, 3-C seismic surveys were performed from October 30, 1995 to December 27, 1995. The initial 3-D, 3-C survey was acquired from October 28 through November 13. CO_2 injection began November 13, 1995 and lasted until December 8, 1995. The "soak" period extended from December 8 through December 28, after which Texaco CVU-97 was returned to production. The second 3-D, 3-C survey was acquired during the "soak" period, from December 21 to December 28.

The compressional data provides a measure of the bulk rock compressibility, rigidity and density, while shear wave data is sensitive to rigidity and density. The combined use of P-wave, S1 shear and S2 shear seismic data allow different views of the bulk rock properties in the subsurface. Our interpretation methodology strives to use these volumes to delineate spatial variations in the subsurface related to lithology, porosity, pore structure variations related to preferred permeability directions, and variations in pore fluid pressure and properties.

Interval travel time comparisons between the P- and shear volumes are a robust and sensitive indicator of lithology, porosity and pore geometry, and the intensity of fracturing. In particular, the Ts1/Tp and Ts2/Tp measures show regions of lower Vp/Vs ratio in the southwest portion of the survey area. This portion of the reservoir produces less fluid with a lower water cut than do areas of the field exhibiting a higher Vp/Vs ratio. The Vp/Vs measure appears strongly correlated with the reservoir production characteristics.

Anomalies between the two seismic surveys are readily visible on both the P-wave and S-wave seismic surveys. These anomalies arise in P-wave amplitude difference maps and variations in S-wave velocity anisotropy. An interpretation of these 4-D, 3-C seismic anomalies indicates that a CO_2 miscible bank formed south of well CVU-97 near well CVU-200, and that the bank is contained by a permeability barrier near well CVU-200. P- wave and Si shear data are delineating reservoir zones where fluid compressibility and/or viscosity have changed due to CO_2 injection and the subsequent migration of lighter hydrocarbons.

The ability to sense bulk rock/fluid properties with 4-D, 3-C seismology enables characterization of the most important transport property of a reservoir, namely permeability. Because of the high volume resolution of the 4-D, 3-C seismic, we can monitor the sweep efficiency of a production process to see if reserves are bypassed by channeling around lower permeability parts of the reservoir and the rate at which the channeling occurs. In doing so, we can change production processes to sweep the reservoir more efficiently.

(38694) Dynamic Reservoir Characterization of a CO_2 Huff'n'Puff, Central Vacuum Unit, Lea County, New Mexico

The Reservoir Characterization Project (RCP) is an industry sponsored consortium whose mission is to develop and apply 3-D and 4-D ("time-lapse"), 3-C seismology and associated technologies to improve reservoir performance and hydrocarbon recovery while reducing environmental impact. RCP Phase VI is the multidisciplinary, 4-D, 3-C study of a CO_2 injection project in Vacuum field, a shallow shelf carbonate reservoir located on the Northwestern Shelf of the Permian Basin of West Texas and Southeastern New Mexico.

The CO_2 "huff-n-puff" in well Texaco CVU-97 at Vacuum Field and the repeated 3-D, 3-C seismic surveys were performed from October 30, 1995 to December 27, 1995. The initial 3-D, 3-C survey was acquired from October 28 through November 13. CO_2 injection began November 13, 1995 and lasted until December 8, 1995. The "soak" period extended from December 8 through December 28, after which Texaco CVU-97 was returned to production. The second 3-D, 3-C survey was acquired during the "soak" period, from December 21 to December 28.

The compressional data provides a measure of the bulk rock compressibility, rigidity and density, while shear wave data is sensitive to rigidity and density. The combined use of P-wave, S1 shear and S2 shear seismic data allow different views of the bulk rock properties in the subsurface. Our interpretation methodology strives to use these volumes to delineate spatial variations in the subsurface related to lithology, porosity, pore structure variations related to preferred permeability directions, and variations in pore fluid pressure and properties.

Interval travel time comparisons between the P- and shear volumes are a robust and sensitive indicator of lithology, porosity and pore geometry, and the intensity of fracturing. In particular, the TS1/TP and TS2/TP measures show regions of lower VP/VS ratio in the southwest portion of the survey area. This portion of the reservoir produces less fluid with a lower water cut than do areas of the field exhibiting a higher VP/VS ratio. The VP/VS measure appears strongly correlated with the reservoir production characteristics.

Anomalies between the two seismic surveys are readily visible on both the P-wave and S-wave seismic surveys. During the CO_2 injection program both the fluid composition and reservoir pore pressure were altered. An interpretation of these seismic anomalies indicates the P-wave and S1 shear data are delineating reservoir zones where fluid compressibility and/or viscosity have changed due to CO_2 injection and the subsequent migration of lighter hydrocarbons. The P-wave and S1 shear data indicate fluid movement to the northwest from CVU-97 along the direction of maximum horizontal stress towards the portion of the reservoir with better effective permeability.

The S2 shear data, on the other hand, appears to be more sensitive to changes in pore pressure or effective stress. As more fractures and low aspect ratio pore structure are opened with increasing pore pressure, the attenuation of the S2 data increases. Mechanisms for the increased attenuation could be related to decreasing the effective stress and local fluid flow processes. The shear-wave polarization is seen to exhibit variation between the initial and repeat surveys consistent with changes in anisotropy due to reservoir processes.

(27656) Potential of the Cyclic CO_2 Process in a Waterflooded, Light Oil, Shallow Shelf Carbonate Reservoir

The goal of this Central Vacuum Unit Project is to demonstrate the CO_2 Huff-n-Puff process in light oil, shallow shelf carbonate reservoir within the Permian Basin. The CO_2 Huff-n-Puff process is a proven enhanced oil recovery (EOR) technology for Louisiana-Texas gulf coast sandstone reservoirs. The reader is referred to three Society of Petroleum Engineers (SPE) papers, No. 15502, 16720 & 20208 for a review of the theory, mechanics and case histories of the process. The process has even been shown to be moderately effective in conjunction with steam on heavy California crude oils. Although the technology is proven in sandstones, it continues to be an underutilized EOR option for carbonates.

BENEFITS: The application of CO_2 technologies in Permian Basin carbonates may do for the decade of the 1990's and beyond, what waterflooding did for this region beginning in the 1950's. With an infrastructure for CO_2 deliveries already in place, a successful demonstration of the CO_2 Huff-n-Puff process will have wide application. Profitability of marginal properties will be maintained until such time as pricing justifies a full-scale CO_2 miscible project. It could maximize recoveries from smaller isolated leases which could never economically support a miscible CO_2 project.

The process, when applied during the installation of a full-scale CO_2 miscible project could mitigate up-front negative cash-flows, possibly to the point of allowing a project to be self-funding and increase horizontal sweep efficiency at the same time. Since most full-scale CO_2 miscible projects are focused on the "sweet spots" of a property, the CO_2 Huff-n-Puff process could concurrently maximize recoveries from non-targeted acreage. An added incentive for the early application of the CO_2 Huff-n-Puff process is that it could provide an early measure of CO_2 injectivity of future full-scale CO_2 miscible projects and improve real-time recovery estimates--reducing economic risk. By virtue of the very same blocking abilities that hamper miscible CO_2 project water injection rates, water production may measurably be reduced--reducing lease operating expense. The CO_2 Huff-n-Puff process could bridge the near-term needs of maintaining this large domestic resource base until the mid-term economic conditions support the widespread implementation of the more efficient full-scale miscible CO_2 projects.

(19666) The Effects of Waterflooding on Reservoir Properties and Producing Operations: Applications for Geochemical Modeling

Detailed analysis of core samples from San Andres Formation dolomites and scale samples from production wells in two Permian Basin reservoirs production wells in two Permian Basin reservoirs document the effects waterflooding has had on the Permian (Guadalupian) Age reservoirs. Anhydrite Permian (Guadalupian) Age reservoirs. Anhydrite dissolution adjacent to an injection well and the precipitation of sulfate scale in producing wells precipitation of sulfate scale in producing wells and equipment are shown to be unequivocally attributable to waterflooding. Geochemical modeling has been used to determine water/water and rock/water compatibilities so that proper water handling techniques could be implemented to improve operational efficiencies and reduce the potential for reservoir and equipment damage potential for reservoir and equipment damage caused by dissolution and/or precipitation of minerals.

NM-East Vacuum (Click East Vacuum to return to table)

(66569) Feasibility of Monitoring CO_2 Sequestration in a Mature Oil Field Time-Lapse Seismic Analysis

A goal of CO_2 sequestration is to provide economically competitive and environmentally safe options to offset projected growth in baseline emissions of greenhouse gases. The sequestration of CO_2 in subsurface formations is a gas storage process. Among the issues that must be considered in a gas storage project are verification of injected gas inventory and monitoring of injected gas migration. This paper uses an integrated flow model to assess the feasibility of monitoring CO_2 sequestration in a mature oil field using time-lapse seismic analysis.

(53714) Management of Water Alternating Gas (WAG) Injection Projects

This paper summarizes the results of several successful WAG projects presented in many Improved Oil Recovery (IOR) Symposiums, indicating the main technical and operational issues considered in the development and implementation of such projects, and the management strategy for monitoring the process. The results from these field applications will serve as useful guides and examples for improving reserves from many of our mature fields, and would lead to rethinking our strategy of reservoir development and new technology application for significant reserves enhancement in Venezuela. The paper focus on the selection of the technical aspects that must be consider in the implementation and management of the Water Alternating Gas (WAG) Injection process, providing an useable reference for the front line geoscientists, reservoir engineers, production operation engineers and technical managers who wish to obtain a technical and operational overview of the process as applied in the petroleum industry.

Managing WAG injection projects requires making decisions regarding to the WAG ratio, half-cycle-slug size, and ultimate solvent slug size for each WAG injector in the field. The impact of these decisions affects the capital cost of solvent purchase, water and gas plant loads, fluid handling and lifting operation costs, and ultimate incremental oil recovery. Simulation models provide a tool for examining strategies for these decisions. However, it must be able to address operational impacts such as lift method and problems, injecting plugging, workovers and facilities operations. Project monitoring incorporating actual performance data into the reservoir models provides an excellent diagnostic tool for decision making. The technical considerations for managing WAG projects presented in this paper can be used as a methodology for monitoring projects performance at pattern and full field level, increasing understanding of the process performance, and improving decision making.

(39793) History Matching and Modeling the CO-Foam Pilot Test at EVGSAU

A pilot area in the East Vacuum Grayburg-San Anders Unit (EVGSAU) was selected for a comprehensive evaluation of the use of foam for improving the effectiveness of a CO flood. The response from the foam field trial was very positive, it successfully demonstrated that field application of CO-foam is a technical viable process for improved oil recovery (IOR). A pseudo-miscible reservoir simulator, MASTER, which was recently modified by incorporating a newly developed foam model, was used to conduct a history match study on the pilot area at EVGSAU to understand the process mechanisms and sensitive parameters. The ultimate purpose was to establish a foam predictive model for CO- foam processes.

In this paper, the history match results are presented. The important modeling considerations that led to an acceptable history match are highlighted and discussed. Finally, the simulated results of a foam predictive ease are presented. The injection schedule of the foam predictive ease was specifically selected to mimic the filed injection schedule used in the foam pilot test at EVGSAU.

The simulated results are consistent with the field pilot test results. Overall, the foam model is found to be adequate for field scale CO-foam simulation. The results also confirm that the communication path between the foam injection well and the offending well had a strong impact on the production performance.

(36710) East Vacuum Grayburg San Andres Unit CO_2 Flood Ten Year Performance Review: Evolution of a Reservoir Management Strategy and Results of WAG Optimization

The East Vacuum Grayburg San Andres Unit (EVGSAU) recently completed ten years of successful CO_2 miscible WAG injection. This paper briefly reviews the original CO_2 project design and field performance over the past ten years, and discusses the evolution of a CO_2 reservoir management strategy from the original, fixed 2:1 WAG design to the current flexible, performance-driven WAG strategy. Variations in the magnitude and character of CO_2 flood response across the Unit due to variability in local reservoir geology presented numerous reservoir management challenges. Problems were encountered in areas such as injection conformance, pattern balancing and sweep efficiency; managing large swings in gas production rates, and changes in injection gas composition and MMP due to construction of an NGL recovery facility.

These challenges required a re-evaluation of our understanding of the reservoir and prompted a review of the original project design and operating philosophy by an interdisciplinary study team. Significant elements of this effort included surveillance and data collection on selected infill wells, extensive reservoir characterization work, and use of operations-oriented simulation modeling. This work resulted in the evolution of a more flexible reservoir management strategy for EVGSAU utilizing selective, geologically-targeted infill drilling, well conversions, pattern realignment, and a performance-driven WAG management strategy. Operating changes implemented over the past two years have produced significant improvements in profitability and performance in terms of both increased oil production and reduced gas handling problems and expenses.

(27798) CO_2 Foam Field Verification Pilot Test at EVGSAU: Phase IIIC--Reservoir Characterization and Response to Foam Injection

This paper summarizes the comprehensive reservoir characterization effort for the foam pilot area and discusses the response to foam injection in the CO_2 Foam Field Verification Pilot Test conducted in the East Vacuum Grayburg San Andre S Unit (EVGSAU) in New Mexico. A detailed study of the pilot pattern geology provided an understanding of the major controls on fluid flow in the foam pattern. Pattern performance data, falloff testing, profile surveys, and interwell tracer results were integrated into the geologic model to guide project design work and provide a framework for interpretation of foam performance. Localized regions of high permeability resulting from solution enhancement of the matrix pore system appear to be the primary cause of the early CO_2 breakthrough and channeling of injected CO_2 toward the problem production well in the foam pattern. Positive response to foam injection is indicated by reduced injectivity and injection profile data in the foam injection well; by results from time sequence monitor logging in the observation well; and by changes in production performance in the high GOR, "offending" production well in the foam pattern. Hall plots and pressure falloff testing were used to measure in situ changes in fluid mobility near the foam injection well. Time sequence logging responses at an observation well located 150 feet from the foam injector provided evidence of changes in fluid flow patterns in response to foam injection. Positive response to foam injection is further evidenced by changes in the CO_2 production and oil rate performance at the "offending" production well in the foam pilot pattern.

(27786) CO_2 Foam Field Verification Pilot Test at EVGSAU: Phase IIIB--Project Operations and Performance Review

This paper summarizes the injection well and production well responses from foam injection in the CO_2 Foam Field Verification Pilot Test that was conducted at the East Vacuum Grayburg-San Andres Unit (EVGSAU). Previous papers have documented various aspects of the four year field trial including the laboratory work leading to the selection of a surfactant as well as the design work and analysis which determined our operating plan. Specifically this paper presents: 1) the positive injection well response as documented with pressure and rate data and profile logs 2) the positive production well response 3) economics and future plans and 4) conclusions. A companion paper presents a summary of the reservoir characterization that influenced fluid flow in the test pattern as well as analysis of Hall plots, falloff testing, tracer surveys and time sequence logging in the observation well located 150 feet from the foam injector.

(27785) CO_2 Foam Field Verification Pilot Test at EVGSAU: Phase IIIA--Surfactant Performance Characterization and Quality Assurance

This paper is a summary of both new and previous laboratory work done in support of the CO_2-foam application in a pilot area of the East Vacuum Grayburg-San Andres Unit (EVGSAU) of southeastern New Mexico. This pilot test was a cooperative effort between the EVGSAU owners, New Mexico PRRC, and the Department of Energy. Different laboratory techniques used for the evaluation of CO_2-foam mobility and surfactant adsorption on reservoir rocks are first discussed briefly. Recent results that concentrate on work with the surfactant selected for use in this field pilot are then presented. These results display CO_2-foam mobility in EVGSAU core samples over wide ranges of surfactant concentration and core permeability. The results generally show a drastically decreased dependence on surfactant concentration above the critical micelle concentration (CMC) and a slightly favorable, but not prominent, dependence of mobility on rock permeability. A further rock sample characteristic pertaining to the initial conditions of the core-from "preserved" through various states of cleaning is also discussed. Additional discussion is given on surfactant absorption, including results of measurements on Baker Dolomite as well as EVGSAU cores. Using refractometric analysis with the recirculation method, the adsorption results were found to be affected by the water salinity and core conditions. Quality control data for the bulk surfactant and injected solutions, and analyses of the produced brine for tracers and surfactant breakthrough are presented. Foam breakers and emulsion breakers were also evaluated for contingency use in case of the appearance of foam or emulsion in production facilities.

(27675) Laboratory Flow Tests Used To Determine Reservoir Simulator Foam Parameters for EVGSAU CO_2 Foam Pilot

This paper presents the results of laboratory foam tests that will be used to determine foam parameters for use in foam-flood reservoir simulators. Foam tests were performed at average reservoir conditions of 101 F and 2100 psig with EVGSAU cores. Foam was generated in situ by simultaneous injection of surfactant solution and CO_2 into a brine-saturated core. In this study, the gas-liquid volumetric injection ratios of 2, 4, and 6 (with foam qualities of 66.7%, 80.0%, and 85.7%, respectively) were examined. The flow rate in terms of total interstitial velocity varied from 0.36 to 34.38 ft/day. The surfactant was tested at concentrations of 1000 and 2500 ppm active.

The resistance factor of each test ranged from 3 to 63, indicating that foam was generated at all the testing conditions. Brine permeability, which changed after each foam test, had a significant effect on the calculation of foam apparent viscosity. Because of varying brine permeability, the resistance factor data is more suitable for simulator input than the apparent viscosity data.

(26478) Reservoir Description by Inverse Modeling: Application to EVGSAU Field

The major problem of conventional geostatistical reservoir characterization by conditional simulation is that none of the equiprobable realizations (permeability and porosity) generated may fit the field data when used in a reservoir simulation. A recently developed inverse modeling procedure was tested on the CO_2-foam pilot area of the East Vacuum Grayburg/San Andres Unit (EVGSAU). The modeling procedure estimated reservoir properties through an automatic and multi-well history matching algorithm. The reservoir parameters, which were estimated by solving an inverse problem, were permeability distribution, average relative permeability and capillary pressure curves, reservoir engineering parameters such as the productivity or injectivity index at the wells, and effective injection rates. All parameters were estimated at reservoir scale in this approach.

A least-square error objective function was minimized by using the simulated annealing method (SAM). The field data matched were the oil, gas, and water productions at each well. The convergence of this new algorithm is guaranteed by the use of SAM, and the permeability distribution generated is conditioned to the dynamic field data. Additionally, for the first time, reservoir engineering parameters were estimated at reservoir scale.

At each iteration, a limited number of reservoir parameters were adjusted. Then, a black oil reservoir simulator was used to evaluate the impact of these new parameters on the field production data. Finally, after comparing the simulated production curves to the field data, a decision was made to keep or reject the altered parameters tested.

A reliable, efficient computer code was developed to estimate reservoir properties by automatic history matching. The algorithm was tested on the EVGSAU for the waterflood period (1980-1985). After optimization, a good match was obtained for all the dynamic field data (production of oil, gas, and water) at all the wells located in the pilot area of the EVGSAU. The resulting large-scale reservoir description was then used to simulate CO_2 injection after 1985. The pilot region production history from 1986-1991 was suitably matched using the waterflood reservoir description.

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet is discussed. The economic impact of EOR tax incentives is also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(24928) Update of Industry Experience with CO_2 Injection

The main purpose of this paper is to utilize current industry experience to evaluate the performance to date of miscible CO_2 injection projects. Also included is a summary of innovations being implemented by industry to improve recovery from existing CO_2 projects. Experience to date has shown that on balance, CO_2 injection projects have performed better than anticipated and offer a significant opportunity for improving ultimate recovery from existing reserves.

(24642) CO_2 Foam Field Verification Pilot Test at EVGSAU: Phase II -Foam Injection Design and Operating Plan

The East Vacuum Grayburg San Andres Unit (EVGSAU) operated by Phillips Petroleum, is the site selected for a comprehensive evaluation of the use of foam for improving the sweep efficiency of a CO_2 flood. The four-year project is jointly funded by the EVGSAU Working Interest Owners (WIO), the U.S. Department of Energy (DOE), and the State of New Mexico. The Petroleum Recovery Research Center (PRRC), a division of the New Mexico Institute of Mining and Technology (NMIMT), is providing laboratory and research support for the project. A Joint Project Advisory Team (JPAT) composed of technical representatives from numerous major oil companies, PRRC, and DOE provides input, review and guidance for the project.

This paper is the second in a series of papers detailing various aspects of the CO_2 Foam Field Verification Pilot test at EVGSAU. An earlier paper summarized the project plans and detailed the laboratory work leading to the selection of a surfactant for the field trial. This paper presents: 1) an overview of the operating plan for the project, 2) details of the foam injection schedule and design criteria, and 3) a discussion of the data collection program and performance criteria to be used in evaluating successful application of foam for mobility control in the EVGSAU CO_2 project.

Specific items discussed in the foam injection design include the determination of surfactant volume and concentration, selection of the surfactant-alternating-gas (SAG) injection sequence for foam generation, field facilities, operations during foam injection, and contingency plans. An extensive data collection program for the project is discussed including production testing, injection well pressure and rate monitoring, injection profiles, production well logging, observation well logging program, and both gas and water phase tracer programs.

(24176) CO_2-Foam Field Verification Pilot Test at EVGSAU Injection Project Phase I: Project Planning and Initial Results

The East Vacuum Grayburg/San Andres Unit (EVGSAU), operated by Phillips Petroleum Company, is the site selected for a comprehensive evaluation of the use of foam for improving the effectiveness of a CO_2 flood. The four-year project is jointly funded by the EVGSAU Working Interest Owners (WIO), the U.S. Department of Energy (DOE), and the State of New Mexico. The Petroleum Recovery Research Center (PRRC), a division of the New Mexico Institute of Mining and Technology (NMIMT), is providing laboratory and research support for the project. A Joint Project Advisory Team (JPAT) composed of technical representatives from numerous major oil companies provides input, review, and guidance for the project.

The EVGSAU, located about 15 miles northwest of Hobbs in Lea County, is the site of the first full-scale miscible carbon dioxide injection project in the state of New Mexico. The 5000 acre CO. project is divided into three water-alternating-gas (WAG) areas where CO_2 injection was initiated in September of 1985. A 2:1 WAG ratio was chosen so that while CO_2 is injected into one area, water is injected into the other two areas of approximately equal pore volumes. After each fourth month of operation, CO_2 injection is rotated into another WAG area.

While tertiary oil response at the EVGSAU is very favorable, some wells are showing excessive CO_2 breakthrough, thereby increasing CO_2 recycling and compression costs. This project includes a field demonstration of the use of foam to reduce the mobility of the injected CO_2, reduce excessive CO_2 production, improve the volumetric sweep efficiency of the injected CO_2, and increase the incremental oil recovery from the tertiary project. Thus, a suitable pattern in the EVGSAU was selected, based on the criterion that the production there be typical of other patterns without a distinctly better or worse record of CO_2 breakthrough than in the rest of the field. An observation well was drilled in the pattern; location of this well is approximately 150 ft from the pattern injection well, The observation well was cored and logged to improve reservoir characterization in the pattern area, as well as to provide reservoir cores for laboratory tests with suitable foam-generating surfactants. In order to use the borehole as a logging monitor well, the bottom 800 ft was cased with fiberglass.

The objective of this four-year project is to conduct reservoir studies, laboratory tests, simulation runs, and field tests to evaluate the use of foam for mobility control or fluid diversion in a CO_2 flood. A geological characterization of the pilot area and surrounding patterns has been assembled for the history matching and reservoir simulation studies that are in progress. The foam-flood mechanistic model developed at the PRRC is being incorporated into the field-scale reservoir simulator.

This paper summarizes the project plans, the baseline field testing, and the laboratory test results that pertain to surfactant selection. This overview provides a background for subsequent papers that will report on various aspects of the project.

(19666) The Effects of Waterflooding on Reservoir Properties and Producing Operations: Applications for Geochemical Modeling

Detailed analysis of core samples from San Andres Formation dolomites and scale samples from production wells in two Permian Basin reservoirs production wells in two Permian Basin reservoirs document the effects waterflooding has had on the Permian (Guadalupian) Age reservoirs. Anhydrite Permian (Guadalupian) Age reservoirs. Anhydrite dissolution adjacent to an injection well and the precipitation of sulfate scale in producing wells precipitation of sulfate scale in producing wells and equipment are shown to be unequivocally attributable to waterflooding. Geochemical modeling has been used to determine water/water and rock/water compatibilities so that proper water handling techniques could be implemented to improve operational efficiencies and reduce the potential for reservoir and equipment damage potential for reservoir and equipment damage caused by dissolution and/or precipitation of minerals.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987

Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(16721) East Vacuum Grayburg-San Andres Unit CO_2 Injection Project: Development and Results to Date

The East Vacuum Grayburg-San Andres Unit, operated by Phillips Petroleum Company, is the site of the first full scale miscible carbon dioxide injection project in the State of New Mexico. Since unitization in December, 1978, the unit has undergone infill drilling, repressurization by water injection, and is now in its second WAG (water-alternating-gas) cycle Of CO_2 injection. Early engineering efforts, based on the high fluid conductivity of the reservoir, prescribed the use of larger than normal downhole equipment in conjunction with the choice of an injection pattern with a high producer to injector ratio. This effort made possible the very short transition time between late primary production and early tertiary development. Due to over thirty years of primary production, reservoir pressure in the unit had fallen well below minimum miscibility pressure. Reservoir repressurization, accomplished with water injection, was conducted prior to the initiation of CO_2 injection in September, 1985. During this time, the injection scheme was also determined, contracts for the purchase and delivery of the CO_2 were negotiated, and design and construction of the CO_2 injection system and produced gas gathering system were completed. Handling of the CO_2 contaminated hydrocarbon gas production was also considered, resulting in the design and construction of a dehydration and reinjection facility. Treatment of the produced gas for the recovery of hydrocarbons is still under investigation.

Results have been encouraging with a large percentage of the wells exhibiting no CO breakthrough to date. However, isolated cases of CO_2 breakthrough have been observed in a small number-of wells in the more heterogeneous section of the tertiary project area. Future plans for the project include continued monitoring of reservoir performance, the evaluation of a proposed ten acre infill pilot project, and optimization of the CO_2 reinjection facility.

NM-State 35 Unit (Hale Mable) (Click State 35 Unit (Hale Mable) to return to table)

(16722) Development and Results of the Hale/Mable Leases Cooperative Polymer EOR Injection Project, Vacuum (Grayburg-San Andres) Field, Lea County, New Mexico

The Vacuum (Grayburg-San Andres) field, located in Lea County, NM (Fig. 1), was discovered in May 1929. The discovery well was the Socony Vacuum Oil Co. Bridges State Well No. 1. Drilling began on the Hale and Mable leases (Fig. 2), located in the southwest area of the field, in late 1937 and early 1938, with production beginning I year later in 1939. Cumulative production for the two leases to May 1, 1983 (the date when water injection was initiated), was 5.531 million bbl [879 x 103 M3] of oil or about 20% of the 27.443 million bbl [4363 x 103 M3] original OH in place (OOIP).

The first waterflood project to be implemented in the field was by Mobil Oil Co. in their Bridges State lease in 1958. Currently there are nine injection projects. Three of the projects are individual lease floods, while the other six are unitized projects. Four of the projects have initiated tertiary EOR injection. The

Texaco-operated Central Vacuum and Vacuum Units and the Phillips-operated Hale/Mable leases cooperative injection project have injected or are injecting polymer, while the Phillips-operated East Vacuum Unit is injecting CO_2.

Performance of all nine projects has shown the Grayburg-San Andres reservoir to be very responsive to water injection; secondary reserves have increased ultimate oil recovery significantly. The Grayburg-San Andres reservoir has also proved amenable to tertiary polymer and CO_2 injection. Performance of the four tertiary injection projects indicates that an appreciable amount of incremental tertiary oil will be recovered. Performance of the Hale/Mable leases polymer EOR injection project has been encouraging. Water injection was initiated in May 1983. Polymer injection was started just 3 months later in Aug. 1983. Oil production peaked in Nov. 1983 and remained on a relatively flat plateau for the next 22 months before declining. Injection-profile surveys were run in all injectors and showed that fluid injection was uniform and proportionate into all the perforated intervals and zones in all wells. Polymer injection improved the mobility ratio and promoted a more efficient sweep throughout the entire project area, increasing ultimate reserves.

The results of reservoir simulation run before the initiation of water and polymer injection indicated that ultimate recovery increased as the time between initial water and initial polymer injection decreased. This is one reason why polymer injection was initiated just 3 months after water injection. The model also indicated that a low-concentration polymer flood would recover just as much incremental polymer flood oil as a higher-concentration polymer flood as long as the total pounds of polymer injected were the same. The increased volume of low-concentration polymer more than offset its decrease in viscosity, and the residual resistance factor benefits owing to the adsorption of polymer were the same following total polymer injection in both floods

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NM-Loco Hills (click Loco Hills to return to table)

(339) Successful Pilot Predicts Bright Future for Loco Hills Water Flood, New Mexico

The Grayburg-San Andres reservoirs of the Artesia- Vacuum trend, Eddy County, N. M., have produced more than 2 million bbl of primary oil. The rock characteristics and production performance of these reservoirs indicate that many of them should yield substantial volumes of secondary oil. This paper describes the performance of one of the most successful waterflood pilot operations in the Artesia-Vacuum trend. The Newmont Oil Co. pilot in the Loco Hills field consisted of six injection wells in a modified five-spot pattern. Existing producing wells were converted to injection and a local water supply was used until response justified construction of a 26-mile pipeline to deliver sufficient water volumes for full development. Production rates in individual pilot wells increased from 400 to more than 18,000 bbl/month by June, 1960. Injectivity profiles indicate that this field must be flooded at high injection rates and pressures to effectively sweep all of the productive sand and that the reservoir appears to be quite sensitive to variations in injection rates. Additional development of Newmont leases surrounding the pilot area has continued, and the project had 15 injection wells and 47 producing wells on Feb. 1, 1962. These properties, which were producing 444 B/D in Aug., 1958, averaged 2,618 B/D in Jan., 1962. Unit volume recoveries in the pilot flood indicate that the Loco Hills field should be one of the more important secondary recovery projects in New Mexico.

NM-Maljamar (Conoco) (Click Maljamar (Conoco) to return to table)

(27784) Effect of Pressure on CO_2 Foam Displacements: A Micromodel Visualization Study

This paper presents the results of a visualization study on the effect of pressure on CO_2-foam displacements at pressures above and below the minimum miscibility pressure (MMP). CO_2-foam visualization experiments were performed by simultaneous injection of surfactant solution and CO_2 into a high-pressure, glass micromodel saturated with Maljamar crude oil. CO_2-foam was generated in situ during the simultaneous injection of surfactant solution and CO_2. Simultaneous injection of brine and CO_2 (WAG) displacements and pure CO_2 displacements were also conducted to provide a reference point for the CO_2-foam displacements. Results of these displacements were compared to examine the effects of pressure and injection mode on displacement performance and mechanisms. Two different kinds of micromodels were used in this study: modified-layer (MLAY) and modified-heterogeneous (MHET) micromodels. Pressures ranging from 775 to 1320 psia were investigated at a system temperature of 90 F. The surfactant solution used was 1% Alipal CD-128 in a 1% NaCl brine.

Results show that sweep efficiencies were generally lower for pressures below the MMP. However, the effect of pressure on sweep efficiency for CO_2-foam displacements was less than for WAG displacements and much less than for pure CO_2 displacements. Sweep efficiencies for CO_2-foam displacements at pressures just below the MMP were as high as above the MMP. Due to the lower density of injected CO_2 near and below the MMP compared to that at higher pressures, the required mass of CO_2 was as little as one-third of that required at higher pressures for similar sweep efficiencies using CO_2-foam. These observations suggest the economical potential of operating CO_2-foam floods at pressures close to and just below the MMP.

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields
CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet is discussed. The economic impact of EOR tax incentives is also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(24111) Prediction of CO_2/Crude Oil Phase Behavior Using Supercritical Fluid Chromatography
In this paper, we describe a method for characterization of crude oils for predictions of phase behavior of CO_2/crude oil mixtures with an equation of state (EOS). The method includes the use of supercritical fluid chromatography (SFC) with CO_2 as the carrier fluid. Pressure-composition diagrams calculated using the Peng-Robinson EOS and this characterization scheme agree well with PVT observations. The advantage of this technique is that it produces predictions of the phase behavior of CO_2/crude oil mixtures with much less experimental effort than is required to perform PVT experiments.

(20109) Automated CO_2 Injection Control and Well Test Monitoring System
A carbon dioxide flood has been implemented in the Conoco operated Maljamar Cooperative Unit (MCA) which features automated control and monitoring of the injection and well testing facilities. A programmable logic controller (PLC) was used to provide the functionality requirements. The injection system design required the PLC to perform continuous closed-loop control of the CO injection well rates and pressures. The well test system design pressures. The well test system design required the PLC to monitor the gas and liquid volumes, control the liquid dump valves, and control the switching of the test header valves. The PLC also functions as a remote terminal unit, transmitting selected information via radio to the host computer for alarm notification, reporting, and database management functions.

This paper describes the instrumentation, PLC system hardware configuration, and PLC system hardware configuration, and programming that was used to perform CO_2 programming that was used to perform CO_2 injection control and well test monitoring at the MCA CO_2 flood.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987
Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience

in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(18976) Innovative Techniques for Converting Old Waterflood Injectors to State-of-the-Art CO_2 Injectors

The success of a CO_2 flood largely depends on the quality of its injection wells. The wells must confine injection to the desired pay intervals and withstand the corrosive nature of CO_2 for the life of the flood. These are difficult goals to achieve considering the primary candidates for CO_2 flooding are mature waterfloods where the wells may have been in service for forty years or more. Casing and cementing practices of the past were often inadequate for a long waterflood life, and are certainly unacceptable for a long term tertiary recovery project.

This paper describes innovative techniques employed in the MCA Unit, located in southeast New Mexico, for converting old waterflood injection wells into state-of-the-art CO_2 injection wells. The solutions developed for the MCA CO_2 Project have considerable application to other CO_2 projects and can be profitably employed to improve projects and can be profitably employed to improve waterflood recovery as well.

(17371) Tracer Surveys To Identify Channels for Remedial Work Prior to CO_2 Injection at MCA Unit, New Mexico

A tracer program to identify channels within the Grayburg/San Andres formations prior to CO_2 injection has been performed and analyzed at the Maljamar Cooperative Agreement (MCA) Unit. For safety and costs reasons two separate interwell tracer surveys or phases were conducted. In the Phase 1 tests tritium was injected into 62 wells through injection headers to identify field areas where channeling occurs. Within 12 weeks, 25 out of 177 producing wells sampled had a response. Tritium was used because it has a larger acceptable response window between its minimum detectable level and the maximum safe peak response than other available radioactive tracers. This first survey provided important design information for the second survey which included tracers with smaller response windows. The Phase 2 tests included the 19 producers with the larger Phase 1 responses and their 27 active offset injectors. With the use of multiple tracers, the Phase 2 tests identified 14 problem injection wells as channeling sources. Unexpectedly, the source of some channels was farther away than the nearest offset injectors. In addition, the two tracer surveys showed that tracer flow is sensitive to changes in operating conditions. Thus, every reasonable effort should be made to perform tracer surveys under normal operating conditions.

(17323) History Match of the Maljamar CO_2 Pilot Performance

A miscible CO_2 flood pilot conducted in the Maljamar field, New Mexico, was formally completed January 1, 1986. This paper presents the results and developments of numerically history matching the 6th (Grayburg) and 9th Massive (San Andres) zone CO_2 pilots. The purpose of this pilot was to gain information that would reduce the operational and economic uncertainties of a full-scale project. Special features of the 5-acre (20,200 m^2) inverted 5-spot pilot include (a) dual (separate) completions in the Grayburg and San Andres zones and (b) two fiberglass-cased logging observation wells for in situ monitoring of oil, brine, and carbon dioxide movement. The logging observation wells illustrated that the miscible CO_2 flood process can significantly reduce oil saturations in the 6th and 9th Massive zones at Maljamar. The high CO_2 retention, high minimum water saturation, and low CO_2 injectivity exhibited in the pilot can be accounted for through relative permeability hysteresis and a possible change in rock wettability. By incorporating these mechanisms into the simulator, a reasonable match of oil and CO_2 production, fluid injectivity, and observation well saturation profiles demonstrated the validity of the approach. The calibrated performance parameters were used as a basis for making fieldwide performance predictions for the Maljamar field.

(15400) Effect of an Aqueous Phase on CO_2/Tetradecane and CO_2/Maljamar, Crude-Oil Systems

Many investigations have been performed on CO_2/alkane and CO_2/crude-oil systems to establish the mechanisms involved in gas miscible-displacement processes. The presence of an aqueous phase, however, should also be processes. The presence of an aqueous phase, however, should also be accounted for. Brine not only exists in the reservoir before any oil production, but also is injected into the formation during waterflooding to production, but also is injected into the formation during waterflooding to maintain high levels of reservoir pressure and to displace oil. Brine is also injected throughout the CO_2 flood to reduce the mobility of the CO_2.

The effect of an aqueous phase traditionally has been accounted for by predicting the solubility of CO_2 in the aqueous phase and subtracting this predicting the solubility of CO_2 in the aqueous phase and subtracting this amount of CO_2 from subsequent EOS flash calculations for the hydrocarbon phases. The purpose of this investigation is to determine experimentally phases. The purpose of this investigation is to determine experimentally the effect of introducing water or brine into a CO_2/hydrocarbon system. An alternative method of predicting the observed phase behavior will also be presented. In this technique, an EOS is first modified to permit an presented. In this technique, an EOS is first modified to permit an accurate prediction of the water or brine density and vapor pressure. Then the mutual solubilities of CO_2 and water or brine are fitted by implementing a mixing rule for asymmetric systems. The EOS is then incorporated into a multiple-phase flash-calculation algorithm. The two calculation schemes will be compared to determine which provides a more realistic description of the experimentally observed effects and the computational requirements associated with each.

(15079) Solubility and Extraction in Multiple-Contact Miscible Displacements: Comparison of N_2 and CO_2 Flow Visualization Experiments

Results of secondary and tertiary displacements of Maljamar crude oil by N_2 and CO_2 are compared to examine the effects of solubility and extraction on local displacement efficiency. The flow visualization experiments were performed in pore networks etched in glass plates. In those experiments, the much higher solubility of CO_2, in the oil caused only marginal improvement in displacement efficiency over that observed for N_2, which was much less soluble. At pressures high enough that CO_2 extracted hydrocarbons efficiently; however, displacements were much more efficient.

Secondary and tertiary displacements in a more heterogeneous glass model are also compared. In a secondary displacement with hi-h solubility but low extraction, adverse capillary and viscous effects limited the area swept to preferential flow paths. High CO_2 solubility did not appear to have significant effects. When water was present in tertiary displacements with efficient extraction and high solubility, combined effects of viscous instability, capillary forces and heterogeneity sharply reduced sweep efficiency below that observed in secondary displacements in the same model.

(14940) The Maljamar CO_2 Pilot: Review and Results

The 5-acre (20X10-3 -m^2) Maljamar tertiary recovery pilot formally ended Jan. 1, 1986. Special features of the pilot formally ended Jan. 1, 1986. Special features of the inverted five-spot pilot included dual (separate) completions in the Grayburg and San Andres zones and two fiberglass-cased logging observation wells for in-situ monitoring of oil, brine, and CO_2 movement. Solutions to operational problems and a determination of the process performance were intermediate objectives of the pilot. Performance was intermediate objectives of the pilot. The major objective was to provide a basis for commercial scale CO_2 floodline economics for, the unit.

CO_2 retention by the reservoir has prevented major CO_2 production. The observation wells indicated that CO_2 contacted the entire vertical section. Operating problems and pilot performance have been different for the problems and pilot performance has been different for the two zones. Problems, injectivity, oil response, and CO_2 production will be discussed by zone. production will be discussed by zone. The pilot successfully met its objectives by providing data on field operations during CO_2 flooding, as well as the process performance data needed to estimate largescale CO_2 flooding results in the field. Operating problems have been largely resolved, incremental oil problems have been largely resolved, incremental oil production has peaked, and performance has been encouraging. production has peaked, and performance has been encouraging. An expansion project is being designed.

(14897) Diffusion of CO_2 at Reservoir Conditions: Models and Measurements

Mathematical models are developed to describe the transport of dissolved CO_2 in a liquid phase, and results of measurements of the diffusivity of CO_2 in hydrocarbons and water at reservoir conditions are reported. The measurements were made with novel techniques based on the direct observation of the motion of an interface caused by the diffusion o CO_2 through oil or oil shielded by water. Diffusion coefficients were determined by fitting the mathematical models to the observed motion of the interfaces. This method allows the measurement of diffusion coefficients without the need to determine phase compositions and is therefore suited to measurements at elevated pressures (reservoir conditions). Measured diffusion coefficients are reported for CO_2 in pentane, decane, and hexadecane at 25deg.C [77deg.F] and pressures up to 6000 kPa [870 psia). Limited measurements of CO_2 diffusion in Maljamar crude oil are also described. In addition, results of measurements for the diffusion of CO_2 in water are presented. These are the first such measurements at high pressures (up to 6000 kPa 1870 psia), correlations of diffusion pressures (up to 6000 kPa 1870 psia). Correlations of diffusion coefficients in liquids at atmospheric pressure are shown to give reasonable estimates of diffusion coefficients for CO_2 in fluids at reservoir conditions. Finally, the measured diffusion coefficients and mathematical models are used to assess the impact of diffusive mixing on CO_2 floods at various length scales to examine the relationship between laboratory-scale corefloods and field- scale displacements.

(14149) Effect of Oil Composition on Minimum Miscibility Pressure-Part 1: Solubility of Hydrocarbons in Dense CO_2

This paper examines the effect of oil composition on the phase behavior of CO_2/hydrocarbon mixtures and, hence, on the development of miscibility in a CO_2 floods. Results of component-partitioning measurements are reported for mixtures of CO_2 with five synthetic oil systems: normal alkanes, branched alkanes, naphthenes, aromatics, and a mixture of all four molecular types. The results of the experiments indicate that unsubstituted ring structures are less soluble in dense CO_2 than branched or normal alkanes with the same number of carbon atoms, but that the addition of alkyl side chains to ring structures improves their solubility. Also reported are component-partitioning measurements for mixtures of CO_2 with three crude oils: Rock Creek (paraffinic), Maljamar (more aromatic), and Rock Creek plus 15 wt% of a mixture of aromatic components. The experimental results suggest that of the many factors that influence extraction of hydrocarbons by dense CO_2, the distribution of molecular weights present in the oil is the most important.

(14148) Four-Phase Flash Equilibrium Calculations Using the Peng-Robinson Equation of State and a Mixing Rule for Asymmetric Systems

A technique for predicting one- to four-phase flash equilibrium is presented for multicomponent systems containing water, such as CO_2/ presented for multicomponent systems containing water, such as CO_2/ crude-oil/H_2O mixtures that characterize the CO_2 miscible flooding of petroleum reservoirs. The Peng-Robinson equation of state (PR-EOS) is used petroleum reservoirs. The Peng-Robinson equation of state (PR-EOS) is used to describe the aqueous and hydrocarbon phases, and an accelerated and stabilized successive-substitution method is used to obtain convergence, even in the near-critical region. In order to describe accurately multiphase equilibria involving water, a recently developed mixing rule for asymmetric systems is incorporated that permits the solubilities of both CO_2 in H_2O and H_2O in CO_2 to be modeled. The equation of state (EOS) is also modified to enable the aqueous-phase density to be predicted accurately. A comparison of predicted and experimental three- and four-phase behaviors is made for a CO_2/Maljamar crude-oil/H_2O mixture at 302.5C [576.5F].

(14147) Experimental Investigation of the Interaction of Phase Behavior With Microscopic Heterogeneity in a CO_2 Flood

This paper reports results of an experimental investigation of the effects of microscopic heterogeneity on local displacement efficiency in a CO_2 flood. Flow-visualization experiments for first-contact miscible displacements are described and compared with effluent composition measurement for the same models. High-pressure flow-visualization experiments for multicontact miscible CO_2 floods are also described. The displacements were performed in two-dimensional (2D) etched glass models made from thin-sections of

San Andres carbonate core from the Maljamar field. Techniques used in preparation of the models are described briefly. Observations of first-contact miscible displacements in heterogeneous models indicate that early breakthrough and a long transition zone occur when preferential flow paths exist in the pore structure. This behavior corresponds to a flowing fraction less than 1 in the Coats-Smith model. Because the 2D models contained no dead-end PV, the results presented indicate that a low flowing fraction can occur if flow velocities in different portions of the pore space differ significantly. Coats-Smith parameters obtained for models were comparable with values obtained in parameters obtained for models were comparable with values obtained in floods performed in reservoir samples. Visual observations of the CO_2/crude-oil displacements indicate that there is an interaction between phase behavior and microscopic heterogeneity. Mixing of nearly pure CO_2 in the preferential flow path with oil in adjacent regions leads to residual oil saturation (ROS) that forms in the preferential path after oil initially present has been displaced.

(13142) Use of Well Logs to Characterize Fluid Flow in the Maljamar CO Pilot

The Maljamar CO_2 pilot in Lea County, NM is a 5-acre [2 x 104 m^2] inverted five-spot pattern. Two zones are being flooded: a Grayburg dolomitic sand at 3,700 ft 11 130 m] and a San Andres dolomite at 4,050 ft [1230 m]. Two logging observation wells, completed with fiberglass casing through the section of interest, are located in line with the center injector and one of the corner producers. Nine months of freshwater injection in the center well was followed by 9 months of brine injection. A series of induction logs monitored the passing of the freshwater/brine interface, providing data for a preliminary passing of the freshwater/brine interface, providing data for a preliminary characterization of flow in the zones. The brine also established a uniform salinity at the observation wells for saturation determination. Gamma-emitting tracers were injected into each zone of the center well as part of a well-to-well tracer study. Frequent gamma ray logs were run in the observation wells to see whether the movement of the tracers could be detected and used to characterize water movement. The results were very encouraging and provided better vertical and time resolution than the induction logs. The numerous responding layers in each zone could be classified by tracer arrival times into only a few basic types. Injection of CO_2 and follow-up brine has been monitored with a series of induction and neutron logs to follow the changes in water and CO_2 saturation as the flood progressed.

(12666) First Results From the Maljamar Carbon Dioxide Pilot

Continuous carbon dioxide injection in the Grayburg/ San Andres formations of the MCA unit has been completed; follow-up brine injection began in December 1983. Incremental oil production began in mid-1983 from the Grayburg zone and six months later from the San Andres.

Special features of the inverted five-spot pilot include (a) separate completions in the Grayburg and San Andres zones; (b) fiberglass-cased logging observation wells for in situ monitoring of oil, brine, and carbon dioxide movement; and (c) gamma- ray emitting tracers for improved vertical resolution of flow zones.

The a priori prediction of the flow behavior in the Grayburg reservoir, developed from core and log data from seven closely spaced wells, was not consistent with pressure interference data, or with the arrival times of tracers at the logging and production wells. At least three different reservoir descriptions match the Grayburg data; the most likely explanation is a change in the effective location of the injection well due to a hydraulic fracture.

(12600) Development and Status of the Maljamar CO_2 Pilot

This paper describes the planning, testing, and decision-making steps that were taken in the development of the tertiary CO_2, flood pilot in the Permian age carbonate rock formations of the Maljamar Cooperative Agreement (MCA) Unit. Injection and production history through 1983, a discussion of operating techniques and problems. and a summary of the logging results at the problems. and a summary of the logging results at the observation wells are given.

(11337) Formation Damage Potential from Carbon Dioxide-Crude Oil Interaction

The rapidly expanding use of carbon dioxide, CO_2, to enhance the production of crude oil has given rise to reports of apparent formation damage covering a wide range of oil and reservoir properties from different parts of the United States. In 1979 research was initiated at New Mexico State University to define the causes and recommend solutions to the CO_2 formation damage problems. One plausible damage mechanism concerns the precipitation of organic particulates as CO_2 dissolves in the reservoir crude.

Three crude oils from pilot CO_2 tests were studied to determine their tendency to form-precipitates at their respective reservoir pressure and temperature. The three crudes selected for study were Wilmington crude (California), Maljamar crude (New Mexico) and Hilly Upland crude (West Virginia).

To estimate formation damage potential for individual crude oils, volumetric flow versus time through an 8 micron absolute filter has been recorded for the crude saturated with CO_2 at temperatures in the range of 77 deg. -123 deg. F (25 deg. -50.5 deg. C) and at pressures in the range of 300-1800 psig (3-18 MPa). The results, surprisingly, show no correlation with the asphaltic content of the crude, previously determined by inducing precipitation by the addition of either pentane or precipitation by the addition of either pentane or hexane to the crude.

NM-Maljamar (Phillips) (Click Maljamar (Phillips) to return to table)

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987

Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

NM-VGSAU (Click VGSAU to return to table)

No articles found, project not yet started, will begin January 2002

TX-Adair San Andres (Click Adair San Andres to return to table)

(19783) An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs

In this paper we present the results of a technical and an economic evaluation of waterflood infill drillings in fourteen Clearfork and eleven San Andres carbonate reservoirs in West Texas. The initial waterflood recovery efficiency and the infill drilling waterflood recovery efficiency were estimated from decline curve analyses. The economic analysis was performed to evaluate the relative profitability of the waterflood infill drilling operations.

For Clearfork units, the estimated initial waterflood recovery efficiency ranged from 9.54 to 32.19% of original oil in place (N) with a medium of 17.75%N; and the infill drilling waterflood recovery efficiency ranged from 13.09 to 52.56%N with a medium of 25.53%N. The medium increase in oil recovery by infill drilling was 7.78%N. For San Andres units, the initial waterflood recovery efficiency ranged from 10.68 to 39.03%N with a medium of 19.97%N; and the infill drilling waterflood recovery efficiency ranged from 13.73 to 44.58%N with a medium of 31.82%N. The medium increase in oil recovery by infill drilling was 11.38%N.

A multi-linear regression analysis was used to establish regression models correlating the initial waterflood and the infill drilling waterflood recovery efficiencies to reservoir and process parameters. For the Clearfork units, the process parameters. For the Clearfork units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 20.39%N and 3.19%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 29.25%N and 2.48%N, respectively. The average increase in oil recovery by infill drilling was 8.86%N. For the San Andres units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 22.09%N and 1. 45%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 32.23%N and 2.73%N, respectively. The average increase in oil recovery by infill drilling was 10.14%N.

Two cases were studied in the economic analyses. Case I economic analysis used past and projected production schedule and economic projected production schedule and economic parameters. For the Clearfork units, the rate of parameters. For the Clearfork units, the rate of return ranged from 18.37% to 125.2% with a mean of 53.3%. The payout ranged from 1.22 years to 6.58 years with a mean of 3.14 years. For the San Andres units, the rate of return ranged from 20.58% to 500.0% with a mean of 157.0%. The payout ranged from 0.36 to 5.43 years with a mean payout ranged from 0.36 to 5.43 years with a mean of 1.77 years.

Case II economic analysis used past and projected production data as though the projects projected production data as though the projects were initiated in January 1988. The base crude oil price of $17.50/STB was assumed in the analyses. For the Clearfork units, the rate of return ranged from 11.41% to 98.80% with a mean of 40.4%. The payout ranged from 1.45 to 6.42 years with a mean of 3.53 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 4.28 years and 3.13 years using $22.50/STB. For the San Andres units, the rate of return ranged from 20.58% to 500.00% with a mean of 157.00%. The payout ranged from 2.36 to 4.91 years with a mean of 2.3 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 2.18 years and 2.00 years using $22.50/STB.

(16854) Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas

This paper presents the results of an economic analysis of infill drilling in 16 carbonate oil reservoirs located in West Texas. The economic analysis included the evaluation of incremental waterflooding recovery over primary and infill drilling recovery over initial waterflooding.

Because of limited field and economic data available for this study, many assumptions were made to complete the economic evaluations. Two major cases of economic evaluation were performed: Case 1 used the past production and economic data to 1986 and the projection of these data from 1986 on to the assumed economic limit, and Case II used the past infill production data as if the projects were initiated in January 1986 and on to the assumed economic limit.

Results showed that about 6811 of the infill drilling projects studied had an infill drilling incremental payout of less than two years with a incremental discounted cash flow rate of greater than 20%. Only 37% of the projects studied had a waterflood incremental economics with the same criteria. Decreasing the well spacing generally decreased the infill drilling incremental payout and increased the incremental cash flow rate of return. As the OOIP/WS (well spacing) increased, the general trend showed an increasing infill drilling incremental net present value.

Results from Case II studies showed that for a $15/STB ($94/m 3) oil price in 1986, about 68% of the infill drilling projects studied had an infill drilling incremental payout of less than two years with an incremental discounted cash flow rate of return greater than 20%. As the OOIP/WS increased, the general trend also showed an increasing infill drilling incremental net present value. When the oil price in 1986 was increased from $15/STB ($94/m 3) to) $25/STB 0157/m 3), the increase " the incremental net present value (INPV) was substantial. For example at a value of 20 for OOIP/WS (Means Field/San Andres), the INPV increased from $76 MM to $122 MM.

TX-Anton Irish (Click Anton Irish to return to table)

(11930) Case History of Large-Volume Fracture Stimulations in a West Texas Waterflood

A very successful fracture stimulation program in a mature West Texas waterflood is documented in this paper. Amoco's Anton Irish Clearfork Unit (AICF) paper. Amoco's Anton Irish Clearfork Unit (AICF) has undergone a 100 well fracture stimulation program since 1979 which has resulted in significant program since 1979 which has resulted in significant increases in oil production.

Hydraulic fracturing has gradually evolved over the years at the Anton Irish field due to experience gained in new stimulation techniques. Fracture stimulations in the 1970's involved pumping 105,000 gallons of gelled water with 65,000 pounds of 20-40 mesh sand at rates as high as 200 barrels per minute. Although nearly all were initially successful, production increases were sometimes not sustained, due possibly to the insufficient amount of sand/proppant utilized in hydraulic fracturing large 400' dolomite pay sections. Fracture stimulations since 1979 have involved pumping 200,000-300,000 pounds of 20-40 mesh sand in 90,000-150,000 gallons, of cross-linked gelled water at 50 barrels per minute (concentrations as high as 14 pounds of sand per gallon of fluid) to create pounds of sand per gallon of fluid) to create propped fractures which have resulted in sustained propped fractures which have resulted in sustained production increases from the affected wells. One production increases from the affected wells. One hundred eighty days after the workover, average per-well production increases of 38 BOPD yielded per-well production increases of 38 BOPD yielded payouts of 3-1/2 months. payouts of 3-1/2 months. This paper will specifically address fracture stimulation results, quality control measures, and mechanical considerations in beam or electrical submersible pumping equipment, as well as post appraise the economics associated with the $8 million program.

TX-Bennett (Click Bennett to return to table)

(35188) Design and Implementation of a Grass-Roots CO_2 Project for the Bennett Ranch Unit

Large-scale CO_2 projects, like those implemented more than a decade ago in the Wasson Field, are not as attractive today because of large capital investments up-front and lower and uncertain oil prices. However, building upon our experience in large-scale floods, as well as recent improvements in the reservoir characterization and simulation technology, a grass-roots CO_2 project can still be made attractive, in today's environment, by high-grading the reservoir resources, staging the development, and re-injecting the produced gas without facilitating a large gas processing plant. The paper contrasts the characteristics of the Bennett Ranch CO_2 project, a CO_2 flood designed today, with traits of CO_2 floods of yesteryear. The paper also highlights the innovative efforts in reducing and delaying the capital expenditures for wells and facilities, resulting in a less than 1 MM$ capital investment prior to the CO_2 injection. Due to small flood patterns, significant production responses have been observed after only 3 months of CO_2 injection.

(18224) Carbonate Stimulation Optimization Using Hydraulic Fracturing Field Testing

Stimulation designs of the Wasson San Andres dolomite have been optimized at the Bennett Ranch Unit through the use of hydraulic fracturing field tests. In-situ measurements of fluid leak-off, vertical distribution of minimum horizontal stress, and fracture propagation overpressures are incorporated into routine stimulation designs of this West Texas carbonate. This "state of the art" design procedure has resulted in a significant increase in oil rate productivity over the more conventional San Andres stimulation techniques. Additionally, the procedure has significantly reduced both the cost per barrel of oil increase, and the water rate increase typically observed following stimulations at the Bennett Ranch Unit.

The hydraulic fracturing field test procedure is described and the interpretation summarized. Observations from the test are discussed and application of the data in stimulation designs is presented. Stimulation procedures evaluated in presented. Stimulation procedures evaluated in this study include; 1) fracture acidizing, 2) sand propped fracture treatments, 3) rock salt diverted propped fracture treatments, 3) rock salt diverted acid treatments, and 4) acid soaks (or squeezes). A summary of the productivity results, by stimulation type, is presented and discussed.

(13095) Improved Formation Evaluation From Pressure and Conventional Cores Taken With Stable Foam-Bennett Ranch Unit (Wasson Field)

The analysis of pressure cores as well as conventional cores taken with stable foam from the San Andres formation in the Bennett Ranch Unit (BRU) of the Wasson field provided a better means of formation evaluation. The pressure-core data enabled correction of conventional-core pressure-core data enabled correction of conventional-core saturations to in-situ conditions. The results of this oil saturation adjustment method corroborate similar procedures cited in the literature. procedures cited in the literature. The pressure at the bit was controlled during the coring operation to minimize the possibility of altering core fluid saturation. Nitrate was used as a tracer material to measure filtrate invasion. The nitrate analyses of the core waters confirmed the lack of filtrate invasion. The foam pressure was adjusted during the coring operation as dictated by surface observations to maintain a balanced condition. Later calculations of these pressures provided a measure of the bottomhole pressure (BHP) provided a measure of the bottomhole pressure (BHP) variations in this thick formation that consists of variable-quality rock. These data provide a qualitative means to evaluate the volumes and paths of injection waters for estimates of the quantity of oil that may be contacted during tertiary recovery operations.

(9798) San Andres Reservoir Pressure Coring Project For Enhanced Oil Recovery Evaluation, Bennett Ranch Unit, Wasson Field, West Texas

During late 1979, Gruy Federal Inc., under contract to DOE, participated with the operator in pressure coring, operations in Texas Pacific BRU No. 310, Bennett Ranch Unit, Wasson field, west Texas. The well was planned as part of a program to continue development of the water- flood unit on 20-acre spacing. In all, 26 cores were cut over a 210-foot interval of the San Andres dolomite. The cored interval extended some 50 feet below the estimated original oil-water contact, allowing evaluation of CO_2 floodable oil saturation in the transition zone. The analysis of the pressure coring data has provided valuable information that could not have been obtained from conventional cores and/or logs.

TX-Brahaney Plains (Click Brahaney Plains to return to table)

No articles found

TX-Cedar Lake (Click Cedar Lake to return to table)

No articles found

TX-Clearfork (and AB Unit) (Click Clearfork (and AB Unit) to return to table)

(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs

Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacing. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

(25853) An Integrated Approach to Characterize Low-Permeability Reservoir Connectivity for Optimal Waterflood Infill Drilling

This study defines and investigates the Hydraulic Interwell Connectivity (HIC) concept to characterize and estimate the reservoir connectivity. This approach is an integrated study of reservoir characterization, geostatistics, production performance and reservoir engineering. In this study HIC is quantitatively defined as the ratio of observed fluid flow rate to a maximum possible (ideal) flow rate between any combinations of any two wells in the producing unit. The spatial distribution of HIC was determined for the net pay of a reservoir by geostatistics. It was used as a guide for selecting infill well locations to optimize waterflood infill drilling. A low permeability carbonate reservoir producing unit, J.L. Johnson "AB" was used to illustrate the application of HIC. In simulation study, three production wells 27, 107 and 109 were realigned according to HIC distribution which resulted in an additional 10% (10,000 STB) of waterflood oil recovery.

(19783) An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs

In this paper we present the results of a technical and an economic evaluation of waterflood infill drillings in fourteen Clearfork and eleven San Andres carbonate reservoirs in West Texas. The initial waterflood recovery efficiency and the infill drilling waterflood recovery efficiency were estimated from decline curve analyses. The economic analysis was performed to evaluate the relative profitability of the waterflood infill drilling operations.

For Clearfork units, the estimated initial waterflood recovery efficiency ranged from 9.54 to 32.19% of original oil in place (N) with a medium of 17.75%N; and the infill drilling waterflood recovery efficiency ranged from 13.09 to 52.56%N with a medium of 25.53%N. The medium increase in oil recovery by infill drilling was 7.78%N. For San Andres units, the initial waterflood recovery efficiency ranged from 10.68 to 39.03%N with a medium of 19.97%N; and the infill drilling waterflood recovery efficiency ranged from 13.73 to 44.58%N with a medium of 31.82%N. The medium increase in oil recovery by infill drilling was 11.38%N.

A multi-linear regression analysis was used to establish regression models correlating the initial waterflood and the infill drilling waterflood recovery efficiencies to reservoir and process parameters. For the Clearfork units, the process parameters. For the Clearfork units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 20.39%N and 3.19%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 29.25%N and 2.48%N, respectively. The average increase in oil recovery by infill drilling was 8.86%N. For the San Andres units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 22.09%N and 1. 45%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 32.23%N and 2.73%N, respectively. The average increase in oil recovery by infill drilling was 10.14%N.

Two cases were studied in the economic analyses. Case I economic analysis used past and projected production schedule and economic projected production schedule and economic parameters. For the Clearfork units, the rate of parameters. For the Clearfork units, the rate of return ranged from 18.37% to 125.2% with a mean of 53.3%. The payout ranged from 1.22 years to 6.58 years with a mean of 3.14 years. For the San Andres units, the rate of return ranged from 20.58% to 500.0% with a mean of 157.0%. The payout ranged from 0.36 to 5.43 years with a mean payout ranged from 0.36 to 5.43 years with a mean of 1.77 years.

Case II economic analysis used past and projected production data as though the projects projected production data as though the projects were initiated in January 1988. The base crude oil price of \$17.50/STB was assumed in the analyses. For the Clearfork units, the rate of return ranged from 11.41% to 98.80% with a mean of 40.4%. The payout ranged from 1.45 to 6.42 years with a mean of 3.53 years. A sensitivity analysis revealed that the average payout using \$12.50/STB was 4.28 years and 3.13 years using \$22.50/STB. For the San Andres units, the rate of return ranged from 20.58% to 500.00% with a mean of 157.00%. The payout ranged from 2.36 to 4.91 years with a mean of 2.3 years. A sensitivity analysis revealed that the average payout using \$12.50/STB was 2.18 years and 2.00 years using \$22.50/STB.

(12017) Waterflooding the Grayburg Formation on the J.L. Johnson AB Lease: Experience in the Johnson Field

The Grayburg formation in the Johnson field, Ector County, TX, is a more complex reservoir than originally believed. Poor response from waterflooding the J.L. Johnson AB lease with 40-acre [161 875-m] five-spots led to development with 20-acre [80 937-m] linedrive patterns. This caused a substantial production increase. patterns. This caused a substantial production increase. Infill drilling led to the discovery of random, anhydrite-filled sections which act as barriers to flow. They are probably interconnected and may be the cause of poor response to injection on wide spacing. Anhydrite barriers may exist both in other parts of the Johnson field and in surrounding fields. These barriers could play an important role in determining how other waterfloods play an important role in determining how other waterfloods are designed.

TX-Cogdell (Click Cogdell to return to table)

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TX-Cordona Lake (Click Cordona Lake to return to table)

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(24928) Update of Industry Experience with CO_2 Injection

The main purpose of this paper is to utilize current industry experience to evaluate the performance to date of miscible CO_2 injection projects. Also included is a summary of innovations being implemented by industry to improve recovery from existing CO_2 projects. Experience to date has shown that on balance, CO_2 injection projects have performed better than anticipated and offer a significant opportunity for improving ultimate recovery from existing reserves.

TX-Dollarhide (Click Dollarhide to return to table)

(39787) Find Grid CO Injection Process Simulation for Dollarhide Devonian Reservoir

Carbon dioxide injection in the Dollarhide Devonian reservoir commenced in May 1985. Subsequently, CO injection was expanded to an area of the majority southern fault block. As of May 1995, CO injection has been implemented in the entire Devonian formation in five phases. Hybrid CO injection was chosen to be the primary mode of operation. During the course of this project, the operator experienced reduction in injectivity when switching to WAG after injecting a 10% hydrocarbon pore volume CO slug in phases 1 and 2. Oil production consequently decreased due to reduced injectivity. This study was designed to answer operation related questions. We selected a 5-spot pattern in the southern fault block for this study partly because it had the longest production history with hybrid CO_2 injection, and also because the study area was not complicated by faults. Forecasts were made over a period of twenty years for four scenarios. The cause of sustained high water cut at the central producer was also investigated. A fine grid model was used in this study in order to compare more accurately the recovery efficiencies between a single CO_2 slug and hybrid CO_2 injection, and to investigate the advantages of operating at a lower pressure.

(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs

Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacings. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

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(20098) Numerical Evaluation of Single-Slug, WAG, and Hybrid CO_2 Injection Processes, Dollarhide Devonian Unit, Andrews County, Texas
This paper summarizes a numerical evaluation of the effectiveness of applying the conventional single-slug and water-alternating-gas (WAG) CO_2 injection processes and an innovative hybrid process at the Dollarhide Devonian Unit, Andrews County, TX. The hybrid process consists of the injection of an initial slug of CO_2 followed by WAG CO_2 and water injection. The study shows that a properly designed hybrid injection process may have the potential to improve CO_2 flood oil recovery.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987
Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(17294) State of the Art Installation of CO_2 Injection Equipment: A Case Study
Corrosion of injection equipment is a common problem in CO_2 miscible injection operations. The two basic mechanisms by which this corrosion occurs are from internal corrosion caused by holidays in the injection tubing coating as well as from external corrosion caused by CO_2 invading the tubing-casing annulus through minute seepages in the downhole injection equipment. Unfortunately. these problems are both common and costly.

In one West Texas CO_2 injection project, Unocal Corporation, using state of the art connection and testing procedures has developed a method of installing downhole CO_2 injection equipment which virtually eliminates this tubing-casing communication. In addition, the internal plastic coating of the tubulars remains intact and holiday free during field handling procedures. The system involves the use of a helium connection test combined with meticulous attention to detail in the field handling and connection of the tubulars.

(17277) Evaluation and Implementation of CO_2 Injection at the Dollarhide Devonian Unit
A carbon dioxide (CO_2) injection project has been underway at the Dollarhide Devonian Unit since May 1985. Through August 1987, 5.8% hydrocarbon pore volume (HCPV) of single slug CO_2 had been injected into the Unit's Phase I CO_2 area with very little breakthrough at producers. Dollarhide's total lack of premature breakthrough is unique among West Texas CO_2 floods and is indicative of unusually high CO_2 sweep efficiency. Through pattern realignment and injection of a 30% HCPV of CO_2, the project is expected to recover 19% original oil-in-place (OOIP), or 26.3 MMSTB.

TX-East Ford (Click East Ford to return to table)
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TX-East Penwell (Click East Penwell to return to table)
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TX-El Mar (Click El Mar to return to table)
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TX-Ford Geraldine (Click Ford Geraldine to return to table)
(39794) Compositional Simulations of a CO Flood in Ford Geraldine Unit, Texas
The Ford Geraldine Unit (FGU), in Reeves and Culberson Counties, West Texas, produces from the Ramsey Sandstone in the upper Bell Canyon Formation. After primary depletion, a major portion of the reservoir was waterflooded in stages from 1969 to 1980 and is currently under a maturing CO flood that was started in 1981. However, because of high initial water saturation of 47.7% and some aquifer encroachment, the structurally low areas in the northeastern part of the reservoir were producing at very high water cut when the primary recovery approached its economic limit in 1968. As a result, this area responded very poorly to waterflood and no significant production has since been realized from this part of the unit. An estimated 10.1 MMSTB of the 12.9 MMSTB original oil in place (OOIP) remains in the reservoir in this area.

This paper presents results of a study in which advanced geologic, geophysical, and engineering reservoir characterization techniques have been applied to this part of the reservoir as a demonstration area for enhanced recovery. A conditionally simulated Stochastic-permeability-distribution model has also been developed. Compositional simulations were performed for CO flood using stochastic and layered permeability distributions and conservative estimates of fluid saturations.

Results indicate that a minimum of 10% of remaining oil in place (ROIP) can be recovered at breakthrough. Despite very high post-waterflood water saturations, the producing water cut gradually declines because of increase in hydrocarbon mobility as the injected CO dissolves in the oil. An important observation is that compositional simulations indicate significant incremental recovery after breakthrough. At the permissible gas-oil ratio (GOR) of 30 MSCF/STB, recovery of over 30% of ROIP is achievable from the demonstration area.

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields
CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(24928) Update of Industry Experience with CO_2 Injection
The main purpose of this paper is to utilize current industry experience to evaluate the performance to date of miscible CO_2 injection projects. Also included is a summary of innovations being implemented by industry to improve recovery from existing CO_2 projects. Experience to date has shown that on balance, CO_2 injection projects have performed better than anticipated and offer a significant opportunity for improving ultimate recovery from existing reserves.

(20227) A Full-Field Numerical Modeling Study for the Ford Geraldine Unit CO_2 Flood
This paper describes a full field numerical modeling study of the on-going Ford Geraldine Unit CO_2 flood. A three-dimensional, miscible-type simulator was used to simulate the project area, which covers 3,850 acres and includes 212 wells. The numerical model was calibrated by matching rates, cumulative production, and pressure history, both field-wide and for individual wells.

The full field model offers the following advantages over a unit or symmetric element model: 1. Proper description of inter-well interference; 2. Honoring the production/injection and workover histories of the individual wells; 3. Preservation of the reservoir heterogeneity; and 4. No scale-up problems or assumptions.

This paper will briefly describe the simulator and the techniques used in the history matching. The effects of adjusting various parameters will be discussed, and the history match for full field and individual wells will be presented.

After satisfactory history matching results were obtained, the model is being used to assist in the Unit CO flood operation. Examples will be discussed demonstrating the importance of the simulator in monitoring and operating the flood.

(20118) The Ford Geraldine Unit CO_2 Flood- Update 1990
This paper updates the operating history of the tertiary CO_2 flood in the Ramsey (Delaware sand) formation of the Ford Geraldine Unit (FGU). The discussion focuses on injection and production history, operational considerations, data collection and monitoring techniques, and plans for the flood.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987
Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(17278) The Ford Geraldine Unit CO_2 Flood: Operating History
This paper describes the operating history of the tertiary CO_2 flood in the Ramsey (Delaware sand) formation of the Ford Geraldine Unit. Injection and production history, operating techniques and problems, and flood monitoring and planning are discussed.

(12197) CO_2 Flood: Design and Initial Operations, Ford Geraldine (Delaware Sand) Unit

A miscible carbon dioxide (CO_2) flood was initiated by Conoco Inc. in a 3850-acre area of the Ford Geraldine (Delaware Sand) Unit in Reeves and Culberson Counties, Texas in February, 1981, after a staged waterflood was nearing completion. The CO_2 supply is a by-product source obtained from the Lone Star Pikes Peak Gas Plant near Fort Stockton. This previously vented product is compressed to a supercritical state and then transported to the Unit through a 112-mile pipeline which has a capacity of 30 MMCFPD. Compression and transmission system design has minimized start-up and operational problems. Capital costs were reduced by utilizing most of the existing waterflood distribution system. Lack of a sufficient and stable CO_2 supply has caused most of the operational problems. New vessels have been installed to better handle production well testing. In addition, a system has been developed and installed to automate all injection and production data so as to provide the surveillance information to properly monitor the flood performance. Response to the limited and unstable CO_2 injection supply has been encouraging. Once additional supplies are secured and response is verified, CO_2 recycle facilities will be installed. In addition, the flood could later be expanded to the remaining 1430-acre northern area of the Unit, which is still under waterflood.

(6883) Pecos River Water Treatment for Water Injection

This paper presents a review of water quality controls utilized in preparing Pecos River water for fluid injection in the Ford Geraldine (Delaware Sand) Unit, Culberson and Reeves Counties, Texas. The nature of Pecos River water has necessitated the Pecos River water has necessitated the combined use of chemical and mechanical water treatments in order to minimize corrosion and the plugging tendency of this water, resulting in a successful waterflood. River water is used in the Ford Geraldine Unit as supplemental water to produced water, and is the only available water source at the required 25,000 BPD rate.

Extensive laboratory and field testing has been conducted to analyze and develop an efficient, economical and operational system of water treatment that utilizes sulfur dioxide to scavenge dissolved oxygen, chlorine to kill bacteria, and upflow filters to remove suspended solids from the raw river water. This paper discusses laboratory data, field data, and total system operational data.

(6383) Field Study - Ford Geraldine (Delaware Sand) Unit

This paper presents a case history of the Ford Geraldine (Delaware Sand) Unit waterflood operation located in Culberson and Reeves Counties, Texas. The Unit, operated by Continental oil Company, is presently under waterflood in the Delaware presently under waterflood in the Delaware Sand. Presented is a discussion of injection pattern selection, injection well interval pattern selection, injection well interval control and monitoring, injected water quality control and, finally, use of reservoir models in prediction and performance matching.

Extensive water injection well work has been performed consisting of running injection profiles on most wells and remedial jobs on wells with poor injection distribution to alter injection profiles and improve vertical sweep efficiency. Injected water quality control is unique in that Pecos River water is used, which necessitates oxygen and bacteria treating in addition to the removal of solids by filtration. Three computer reservoir simulation model studies have been run to match performance, to date, and to assist in selection of infill well locations.

Specifically, the significance of the Ford Geraldine (Delaware Sand) Unit waterflood is that it is one of the very few successful waterfloods in the Delaware Sand. Field data, lab data, and computer modeling work will be presented in the discussion.

TX-Garza (Click Garza to return to table)

No relevant articles found

TX-GMK South (Click GMK South to return to table)

(19046) Utilization of a Black-Oil Simulator as a Monitor of Waterflood Operations in a San Andres Reservoir

A two phase 3-D model was used to historically match and then predict performance of the GMK South (San Andres) Field. A reservoir management performance of the GMK South (San Andres) Field. A reservoir management team approach consisting of geologists, petrologists and reservoir engineers led to a more complete reservoir description prior to simulation.

Well log analysis and geology work resulted in identification of three distinct layers. Further analysis indicated that Layer 1 contributes less than one percent to the total flow while Layer 3 has insignificant amounts of recoverable oil. This description led to the conclusion that only Layer 2 needed to be considered for a depletion and waterflood performance simulation study. performance simulation study. Because of the heterogeneous nature of the San Andres formation, results of fall-off tests (Kh's) and actual well performance data were necessary for a complete reservoir description, Five sets of pseudo relative permeability curves were needed to achieve a match of historical permeability curves were needed to achieve a match of historical performance. A close examination of production data also led to performance. A close examination of production data also led to identification or better definition of communication within Layer 2.

Prediction calculations were made to project recovery under waterflood Prediction calculations were made to project recovery under waterflood operations. The oil saturation distribution at the end of the waterflood will be input to a compositional model to investigate recoveries from a CO_2 flood program.

TX-Goldsmith (Click Goldsmith to return to table)

(48945) Goldsmith San Andres Unit CO_2 Pilot - Design, Implementation, and Early Performance

This paper describes the evaluation, design, implementation, and operation of a large miscible CO_2 tertiary pilot in the Goldsmith San Andres Unit (GSAU), Ector County, Texas.

The pilot consists of nine inverted (injector-centered) 5-spot patterns covering approximately 320 acres and is located in a mature area of the field where the majority of the wells had been plugged due to high water cuts. The pilot location was selected based on geology and reservoir performance during waterflood. A CO_2 pilot was chosen, rather than full- field implementation, to investigate uncertainties associated with the CO_2 target oil saturation, the feasibility of re-entering abandoned wellbores, and overall CO_2 flood performance. CO_2 injection in the pilot commenced in December of 1996.

The project benefited from available technology on CO_2 flooding and particularly from information on other San Andres CO_2 floods. The paper summarizes the methods used in the early project evaluation/design, data acquisition programs, reservoir simulation and CO_2 flood predictions, and project implementation. The reservoir management plan, actual performance to date, and future potential are also discussed.

The process used (methodology and technical analysis) to evaluate and design the GSAU CO_2 pilot are applicable to other potential Permian Basin CO_2 floods.

(39514) Use, Quantification and Learnings from a Vertical Pulse Test Conducted for Barrier

A vertical pulse test was conducted in a water injector in the Goldsmith San Andres Unit (GSAU) in West Texas for determining the integrity of a low permeability barrier separating two carbonate facies. This test was conducted as part of a CO_2 pilot project. The effective vertical sweep efficiency is controlled by the barrier and is important to quantify.

The pulse test design was tempered by tailing it with a standard interference sequence to mitigate unforeseen situations. This proved useful as the reservoir pressure was lower than anticipated and the well went on vacuum. The data was interpreted using conventional techniques and numerical modeling. The numerical model was tuned to provide transient quality results by comparing against standard analytical solutions before using it to interpret the pulse test.

This paper presents the conduct, analysis and interpretation of the vertical pulse test and discusses some of the findings. Sensitivity analysis was performed on slab, layercake and geostatistical models for the flooding pattern, to understand the influence of small scale heterogeneity on short tests. The results indicate that one can distinguish between a casing leak and reservoir vertical communication from a pulse test. The vertical permeability governs the peak arrival and magnitude of the pulses whereas the horizontal permeability controls the magnitude and shape of the fall off portions of the test.

(20137) Evaluation of Alternating Phase Fracture Acidizing Treatment Using Measured Bottomhole Pressure

Net fracturing pressure calculated from measured bottomhole pressure verifies the effectiveness of the alternating phase technique for controlling acid fluid loss. Results of before and after job simulation cases modeling the process are shown. Subsequent pressure buildup data are also presented.

(16854) Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas

This paper presents the results of an economic analysis of infill drilling in 16 carbonate oil reservoirs located in West Texas. The economic analysis included the evaluation of incremental waterflooding recovery over primary and infill drilling recovery over initial waterflooding.

Because of limited field and economic data available for this study, many assumptions were made to complete the economic evaluations. Two major cases of economic evaluation were performed: Case 1 used the past production and economic data to 1986 and the projection of these data from 1986 on to the assumed economic limit, and Case II used the past infill production data as if the projects were initiated in January 1986 and on to the assumed economic limit.

Results showed that about 6811 of the infill drilling projects studied had an infill drilling incremental payout of less than two years with a incremental discounted cash flow rate of greater than 20%. Only 37% of the projects studied had a waterflood incremental economics with the same criteria. Decreasing the well spacing generally decreased the infill drilling incremental payout and increased the incremental cash flow rate of return. As the OOIP/WS (well spacing) increased, the general trend showed an increasing infill drilling incremental net present value.

Results from Case II studies showed that for a $15/STB ($94/m 3) oil price in 1986, about 68% of the infill drilling projects studied had an infill drilling incremental payout of less than two years with an incremental discounted cash flow rate of return greater than 20%. As the OOIP/WS increased, the general trend also showed an increasing infill drilling incremental net present value. When the oil price in 1986 was increased from $15/STB ($94/m 3) to) $25/STB 0157/m 3), the increase " the incremental net present value (INPV) was substantial. For example at a value of 20 for OOIP/WS (Means Field/San Andres), the INPV increased from $76 MM to $122 MM.

(9719) Response of North Cowden and Goldsmith Crudes to Carbon Dioxide Slugs Pushed by Nitrogen

Laboratory studies have been conducted to determine oil recovery of the North Cowden-Grayburg and Goldsmith 5,600-ft [1700-m] Clearfork crudes of west Texas when pushed by CO_2 at various pressures. Studies were made pushed by CO_2 at various pressures. Studies were made at reservoir temperatures of 100 and 111 degrees F [38 and 44 degrees C] for the North Cowden and Goldsmith 5,600-ft [1700-m] crudes, respectively. At these temperatures, it was found that the oil recovery ranged from 57 to 99% as the CO_2 pressure increased from 700 psi to 1,800 psi [4.8 to 12.4 MPa]. Normally the North Cowden crude gave a higher oil recovery throughout the pressure range. In recognition that CO_2 may be in short supply, studies were made of the possibility of using a slug of CO_2 pushed by nitrogen. For the slug tests the CO_2 slugs pushed by nitrogen. For the slug tests the CO_2 slugs ranged from 2.5% to 25% HCPV. All CO_2 slugs were pushed by nitrogen. The oil recovery ranged from pushed by nitrogen. The oil recovery ranged from approximately 60 to 99% over this slug size. The data were obtained in slim-tube equipment ranging from 40 to 100 ft [12 to 30 m] in length.

The miscible bank formed between the CO_2 and the body of the crude oil was observed to be a clear straw colored liquid. The analyses of the clear liquid and crude oil conclusively demonstrate (1) that the crude oil undergoes a continuous fractionation process when miscibly displaced by CO_2, (2) the need for tong flow tests, and (3) the inability to interpret most PVT cell data in terms of miscibility.

(1888) Gas Turbine Driven Centrifugal Pumps for High Pressure Water Injection
The experience of Gulf Oil Corp. in the installation and operation of gas turbines as prime movers for centrifugal pumps in high pressure water injection leads to the following conclusions:
1. Installation of gas turbines and centrifugal pumps can be made with very little difficulty. Only a fraction of the foundation is required for this type of installation as compared with other types using heavier equipment. Vibration of equipment and piping is practically eliminated.
2. It is felt that where low cost gas is available, two-shaft gas turbines driving centrifugal pumps are an economical and flexible high pressure water injection installation.
3. Centrifugal pumps normally require less attendance than plunger pumps.
4. Station construction costs compare favorably with other stations utilizing different types of prime movers and pumps.
5. Centrifugal pumps can be designed for almost any condition of high pressure water injection, but there are certain conditions in which plunger pumps are more economical. When the volumes are low and the head high, plunger pumps are usually more economical.
6. Gas turbines are easily automated for unattended operation.
7. Several operating problems were experienced, but subsequent modifications now have provided for a highly satisfactory operation.
8. Fuel consumption compares favorably with that of other types of gas engines.
9. Maintenance and repair cost of the pump has been much lower than anticipated and gas turbine costs have been slightly higher than originally anticipated.
10. The over-all operation is economically attractive.

TX-Hanford (Click Hanford to return to table)

(20229) A Case History of the Hanford San Andres Miscible CO_2 Project
A full-scale miscible CO_2 project was implemented in the Hanford (San Andres) Unit, Gaines County, TX. Unique aspects of the Hanford CO_2 project include the following: (1) CO_2 injection began only 1 year after initiation of water injection; (2) the unit is run by an independent operator; (3) the field has an abundance of modern logs, core data, and pressure data available because it was discovered recently; and (4) a successful technique for correcting injection profiles was developed. The project's design, development, surveillance, and performance are discussed.

TX-Hanford East (Click Hanford East to return to table)

No articles found

TX-Hansford Marmaton (Click Hansford Marmaton to return to table)

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields
CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987
Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience

in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(17327) CO_2 Injection Increases Hansford Marmaton Production

A full-scale CO_2 EOR project initiated in June 1980 at the Hansford Marmaton field in the Texas Panhandle used CO_2 from an anhydrous ammonia plant 46 miles [74 km] away. Unique features of the project include the use of CO_2 to repressurize the reservoir after primary depletion and of treated sewer water to displace the CO_2 bank. This paper reviews the performance of the field under CO_2 injection and explores operational features of the project, including the use of sewer water as an additional injectant. Surveillance techniques and project economics are also presented.

"Production response has been superb since CO_2 injection began in June 1980. Oil rates have increased from 30 to more than 600 B/D [4.8 to 95.4 m3/d]."

TX-Huntley (Click Huntley to return to table)

(27762) A Probabilistic Forecasting Method for the Huntley CO_2 Projects

Two words describe our past approach to miscible CO_2 economic forecasting: deterministic and optimistic. In order to assess the Huntley CO_2 projects more probabilistically and realistically, a team was formed. The team identified five primary areas of risk that are specific to CO_2 projects. The team used judgement, experience, and historic information to assign probability distributions to these areas. Monte Carlo simulation was then used to calculate the distribution of economic outcomes. The mean values of the resulting economic indicators were 20% to 36% below the previously calculated deterministic solutions. This paper describes the method that the team developed, the distributions that were used, what risks were excluded and why, and the resources that were used.

TX-Jess Burnes (Click Jess Burnes to return to table)

No articles found

TX-Kingdom Abo (Click Kingdom Abo to return to table)

(9720) Early Implementation of a Full-Scale Waterflood in the Abo Reef, Terry Co. TX. - A Case History

The kingdom Abo Reef Field, located in the north- western portion of Terry County, Texas is a relatively recent discovery along a linear organic bank trend which is intermittently productive from Eddy County, New Mexico to Hockley County, Texas (Fig. 1). Gulf Oil Corporation operates a major portion of the Kingdom Abo Reef Field, thus enabling Gulf to rapidly apply the technology that is highlighted in this paper. paper. The first part of this paper deals with the history and initial development of the field with the objective of providing a basis for a waterflood project. The emphasis is placed not on the project. The emphasis is placed not on the development of new technology, but rather the application of existing technology in characterizing the reservoir to assist in the early recognition of a low primary recovery factor. An analysis of basic data primary recovery factor. An analysis of basic data taken during development and early production operations led to the conclusion that primary operations would result in a low primary recovery, which provides the setting for the waterflood feasibility provides the setting for the waterflood feasibility study. The description of the waterflood feasibility study emphasizes the specific methodology employed to predict the waterflood performance. The physical development of the waterflood is discussed which emphasizes both the infill expansion project and the water-injection systems. The paper project and the water-injection systems. The paper concludes with a discussion of the present operations and a review of the flood's performance.

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TX-Levelland (Click Levelland to return to table)

(71496) Physical Effects of WAG Fluids on Carbonate Core Plugs

It is a given that carbonate mineral dissolution and deposition occur in a formation in geologic time and are expected to some degree in carbon dioxide (CO_2) floods. Water-alternating-gas (WAG) core flood experiments conducted on limestone and dolomite core plugs confirm that these processes can occur over relatively short time periods (hours to days) and in close proximity to each other.

(25413) Application of a Three-Dimensional Hydraulic Fracturing Simulator for Design of Acid Fracturing Treatments

Recent field experience shows that application of a three-dimensional hydraulic fracturing simulator leads to increased success of acid fracturing well treatments. Fracture extension can be limited to the oil bearing pay, maximum lateral extension can be realized within the height constraint, and acid-rock contact time can be increased many fold. Oil production response can be improved over other stimulation designs while limiting water production response. These methods have been applied in mature waterfloods of the Permian Basin and Cedar Creek Anticline.

(23974) Analysis of Tertiary Injectivity of Carbon Dioxide

The most important conclusions is that the mixing phenomenon due to dispersion, crossflow and viscous instability that models neglect can significantly influence injectivity. The results indicate that three-phase flow of gas, oil and brine needs to be modeled and that, contrary to the conclusions of other investigators, three-phase flow effects can have important influences on injectivity, even when CO_2 is injected above its MMP. In addition, the most sensitive relative permeability parameters for reservoir-scale, tertiary CO_2 flooding conditions in parameters for reservoir-scale, tertiary CO_2 flooding conditions in the presence of correlated permeability heterogeneity are identified. Sensitivity to the relative permeability parameters can also be substantial, even at low permeability contrast. The results presented in this paper are particularly pertinent to the hybrid-WAG displacement process since they provide information about the first cycle of CO_2 injection.

(16854) Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas

This paper presents the results of an economic analysis of infill drilling in 16 carbonate oil reservoirs located in West Texas. The economic analysis included the evaluation of incremental waterflooding recovery over primary and infill drilling recovery over initial waterflooding.

Because of limited field and economic data available for this study, many assumptions were made to complete the economic evaluations. Two major cases of economic evaluation were performed: Case 1 used the past production and economic data to 1986 and the projection of these data from 1986 on to the assumed economic limit, and Case II used the past infill production data as if the projects were initiated in January 1986 and on to the assumed economic limit.

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(16716) The Effects of CO_2 Flooding on Wettability of West Texas Dolomitic Formations

Reduced water injectivity after CO_2 injection has frequently occurred in West Texas oil fields. One explanation proposed for this phenomenon was a change in rock wettability by the CO_2 and crude oil miscible bank. This paper describes an experimental study to determine the effects Of CO_2 flooding on the wettability of West Texas dolomitic cores.

This study examined the relative permeability characteristics of fresh-state San Andres and Grayburg dolomite core samples before and after passing a crude Oil/CO_2 miscible front through the test core. Changes in the relative permeability characteristics were used to infer the effects Of CO_2 flooding on rock wettability. The cores chosen were intermediate oil wet, intermediate, and intermediate water wet. The results showed that the cores became slightly more water wet. However, this change in wettability was near the limit of statistical confidence. Some data suggests that the tendency to becoming water wet was cause by slight rock dissolution by the CO_2 and brine. Some observations concerning the compatibility of brines used in laboratory core floods with dolomites containing anhydrite are discussed.

(14308) Investigation of Unexpectedly Low Field-Observed Fluid Mobilities During Some CO_2 Tertiary Floods

Phase behavior, inorganic precipitation, and wettability are investigated as possible reasons for the unexpectedly low field-observed mobilities during some CO_2 floods, in particular, the Denver Unit, Wasson field CO_2 pilot. The observed mobility was not a near-wellbore effect and probably played a major role in reservoir sweep: the low effective probably played a major role in reservoir sweep: the low effective permeability offset the detrimentally low CO_2 viscosity. Experimental and permeability offset the detrimentally low CO_2 viscosity. Experimental and simulation studies, supplemented by literature data, lead to the conclusion that rock wettability could be the root cause of these low fluid mobilities. Phase behavior effects, though they may play a role, are not necessary to explain the injectivity behavior, and inorganic precipitates probably have little effect under the conditions investigated here. Thus, probably have little effect under the conditions investigated here. Thus, current simulator modeling of low fluid mobilities, which are based on arbitrary permeability reduction factors allegedly caused by phase behavior, appears unjustifiable even though overall simulator results may be acceptable.

(12148) Pilot Plant Performance of Triethanolamine for Bulk CO_2 Separation

Pilot tests have been conducted at a Levelland (TX) Pilot tests have been conducted at a Levelland (TX) gasoline plant to evaluate triethanolamine (TEA), a tertiary amine, for bulk CO_2 separation from a hydrocarbon-rich gas, which simulates that produced during CO_2 miscible flooding. Many operating parameters were evaluated, including contactor pressure, amine temperature, amine circulation rate and concentration, CO_2 content in the feed gas, and various methods of amine regeneration. Bulk CO_2 removal from streams containing from 37 to 67% CO_2 was demonstrated successfully, with minimum input of heat and good hydrocarbon selectivity.

(11121) Use of a Novel Liquid Gelling Agent for Acidizing in the Levelland Field
The San Andres dolomite formation of the Levelland Field in Hockley County, Texas is typically stimulated by acidizing. The types of treatments include workovers of production and injection wells, and initial stimulations of infill drilled wells. This formation is naturally fractured and normally produces a large quantity of released fines following an acidizing treatment. Gelled acid systems are beneficial in stimulation of these type formations due to decreased fluid leakoff and improved fines suspending ability. Several types of acid gelling systems based on polymers are presently available. The use of residual polymer or degraded polymer residue in the Levelland Field may polymer or degraded polymer residue in the Levelland Field may prevent complete recovery of treating fluids and fines. Prevent complete recovery of treating fluids and fines. A gelling agent based on surfactant rather than polymer chemistry has been found to exhibit some unique foam properties in laboratory experiments. Acid gelled with this novel thickener required no additional foaming surfactants, gave higher quality foams than polymer thickened acids of equal viscosity, and allowed stable polymer thickened acids of equal viscosity, and allowed stable foams to be prepared which contained less than 50% nitrogen.

An evaluation of this gelling-foaming system has been done in the Levelland Field. A comparison is made based on field results between regular acid and other gelled acid systems. Wells with similar pay quality were selected using log and other analyses and comparative treatments were performed. Details of these treatments and production results are given in the paper. Cumulative production data one year after treatment revealed foamed surfactant gelled acid to be the most effective treatment for initial stimulations.

Further evaluation of acid gelling systems is presented in the paper through a composite of results from surfactant gelled and paper through a composite of results from surfactant gelled and conventional acid treatments involving workovers of producing wells.

Although many treating variables were not constant, production results from surfactant gelled acid indicates substantial improvement over more conventional acid systems.

(9786) Utilization of Composition Observation Wells in a West Texas CO_2 Pilot Flood
Two composition observation wells were drilled in a tertiary CO_2 Plot in the Levelland Field, Hockley County, Texas. The purposes of these wells were to 1) confirm the laboratory determined mechanism of oil displacement from the composition analysis of mobilized fluids; 2) obtain mixing zone length and growth information to improve estimates of CO_2 requirements for fieldwide floods; 3) determine relative mobilities of the various banks, and 4) obtain information on CO_2 -reservoir rock interactions.

Composition observation wells were drilled 15.2m and 44.2m from an injection well and inline with a central producing well. The composition wells were completed in a 10.7m interval of the total 54.9m pay section. Representative reservoir fluid samples were obtained periodically (usually once a week) from these wells through the use of a bottom-hole sampler, and the volumes of the various fluids (gas, oil, and water) collected were measured. The composition of the hydrocarbons was determined by chromatography techniques. This permitted a composition profile of the oil moving zone permitted a composition profile of the oil moving zone (CO_2 -oil mixing zone) to be determined for each of the wells. The ionic concentration in the water was determined by standard mineral analyses.

Composition data confirmed miscible tertiary oil displacement. A small CO_2 -free oil bank was detected followed by a relatively large oil moving zone which grew with distance traveled from the injection well. The initial analysis of the oil moving zone growth was consistent with a laboratory determined correlation based on first contact miscible fluids. Volumetric data, which are the changes in bottom-hole water-oil ratio with time, indicated more than one zone was swept by the carbon dioxide. Logging observation well data confirmed this conclusion. Bottom-hole pressure data recorded in the composition observation wells showed a cyclic trend with higher pressures occurring during the CO_2 injection cycle and lower pressures occurring during the water injection cycle. Preliminary calculations of the total mobility of fluids flowing between the observation wells suggested an in-depth mobility reduction during the CO_2 slug process as compared to the pre-CO_2 waterflood. Analyses of the water obtained in the sampler indicated CO_2 displaces connate water and slowly reacts with the reservoir rock.

(9785) Carbon Dioxide Displacement of a West Texas Reservoir Oil

This paper presents results of an extensive study to understand CO_2 displacement of Levelland (TX) reservoir oil. The work was conducted to support Levelland CO_2 pilots currently in progress. Experimental displacement tests were conducted at various pressures, core lengths, and CO_2 frontal advance rates. The experimental system included a novel analytical technique to obtain effluent compositional profiles within the oil-moving zone at test conditions. The results of this study show that at pressures greater than the CO_2 minimum miscibility pressure (MMP), a multicontact miscible displacement mechanism predominates. Miscibility is developed in situ by vaporization or extraction-type mass transfer. The laboratory lengths required for CO_2 to develop miscibility and exhibit miscible displacement efficiency were found dependent on the phase equilibria of the CO_2/Levelland oil system. Displacements requiring the greatest length to develop miscibility were at pressures where single-contact mixtures of CO_2 and Levelland oil form two liquid phases. A companion paper demonstrates the use of the analytical technique developed in this study to obtain process data from a CO_2 field pilot test. In addition, the mechanistic process data from a CO_2 field pilot test. In addition, the mechanistic information obtained from this study is used to interpret the process data from the pilot test. The results have application to other reservoir oils whose phase equilibria with CO_2 are similar to the CO_2/ phase equilibria with CO_2 are similar to the CO_2/ Levelland oil system.

(9764) Injection Well Workover Program in the Levelland Field: A Case History

Sun Production Company performed a workover program in which 14 injection wells were selectively acidized to improve injection profiles. Sixty-four percent of the workovers were successful in profiles. Sixty-four percent of the workovers were successful in improving vertical distribution of water injection. Increased oil production paid out the project in less than a year and raised the production paid out the project in less than a year and raised the secondary reserves estimate by 657,000 bbls.

(8831) Design and Implementation of a Levelland Unit CO_2 Tertiary Pilot

Amoco Production Company installed a contained 1.5 acre (6 070m^2) tertiary pilot project in the Levelland Field, Hockley County, Texas in 1978 in order to measure oil displacement that could be obtained by the carbon dioxide miscible recovery process in a completely waterflooded portion of the process in a completely waterflooded portion of the San Andres reservoir.

The pilot was located in a previously waterflooded portion of the reservoir. Sizing of the pilot was portion of the reservoir. Sizing of the pilot was based on available log and core data utilizing a channel flow reservoir simulator which was designed to simulate miscible flood behavior. Special steps were taken during the drilling of the pilot wells to insure controlled placement of the bottomhole locations. Extensive reservoir delineation testing took place prior to starting carbon dioxide injection. Significant prior to starting carbon dioxide injection. Significant information concerning carbon dioxide process feasibility is anticipated from this pilot. Steps taken to design, install, and operate the pilot are described.

(8410) Design and Operation of the Levelland Unit CO_2 Injection Facility

The Levelland CO_2 Facility provides CO_2 storage and handling capacity for the five CO_2 injection pilots located in the Levelland Unit. Facilities pilots located in the Levelland Unit. Facilities were designed for a continuous injection capacity of 3.6 x 10(5) kg of CO_2 (400 tons) per day, making it one of the largest liquid CO_2 injection facilities in operation. The Levelland CO_2 Facility began CO_2 injection in November 1978 and is operating successfully, without most of the problems frequently encountered in liquid CO_2 pumping systems.

(5826) Enriched-Gas Miscible Flooding: A Case History of the Levelland Unit Secondary Miscible Project

Performance is reviewed of an enriched hydrocarbon-gas Performance is reviewed of an enriched hydrocarbon-gas miscible-displacement process in the Levelland Unit. Cyclic injection of enriched gas and water has been in progress for about 4 years. No significant operational problems have been encountered. The project is experiencing response, but peak response has not yet been reached. Performance indicates this project will be an economic success. Performance indicates this project will be an economic success.

TX-Mabee (Click Mabee to return to table)

(71496) Physical Effects of WAG Fluids on Carbonate Core Plugs

It is a given that carbonate mineral dissolution and deposition occur in a formation in geologic time and are expected to some degree in carbon dioxide (CO_2) floods. Water-alternating-gas (WAG) core flood experiments conducted on limestone and dolomite core plugs confirm that these processes can occur over relatively short time periods (hours to days) and in close proximity to each other.

(24163) Interpretation of a CO_2 WAG Injectivity Test in the San Andres Formation Using a Compositional Simulator

Compositional simulation of the field test indicates that the reservoir response during the first cycles of CO_2 and brine injection, including the initial increasing CO_2 injectivity trend and higher brine injectivity after the first CO_2 cycle, are consistent with measured relative permeability, phase behavior, and reservoir characterization data, but that the observed injectivity increase during the second cycle of CO_2 injection cannot be attributed to either the near-wellbore condition of the reservoir at the start of the test or to the presence of thief zones that are statistically consistent with measured core data and well logs. Injectivity is a key variable in determining the economic incentive associated with a proposed CO_2 project, and an important implication of this study is the validation of compositional simulation as a means for interpreting field tests and developing improved predictions of reservoir injectivity performance. Another important conclusion is that geostatistical techniques can be used successfully to characterize high heterogeneity in carbonate reservoirs for injectivity calculations.

(22653) A Laboratory and Field Injectivity Study: CO_2 WAG in the San Andres Formation of West Texas

Laboratory measurements of CO_2 and brine injectivities in restored San Andres carbonate cores at reservoir conditions are reported. Included are results both with unsaturated CO_2 and brine as well as with brine equilibrated with CO_2 and CO_2 equilibrated with brine. A waterflood, oilflood, and miscible flood followed by many cycles of CO_2 and brine injection were done. Important results are the following: endpoint CO_2 relative permeabilities were substantially smaller permeabilities were substantially smaller than both water and oil endpoint relative permeabilities making CO_2 less mobile than permeabilities making CO_2 less mobile than would be anticipated just from viscosity ratios, the irreducible water saturation increased after an oilflood and persisted during subsequent CO_2 floods, residual CO_2 saturations to saturated brine were about the same magnitude as the residual oil saturations to waterflood, and the injectivity of unsaturated brine was much higher than saturated brine because of the absorption of the CO_2 phase.

The laboratory work was done in support of an injectivity field trial. The results of an injection of two cycles of CO_2 and of brine into a well in the Mabee Field in the San Andres formation are reported. Both the CO_2 and the brine field injectivities were significantly greater than the pre-CO_2 waterflood injectivity on a volumetric basis. Field injectivities were significantly greater than would be anticipated from the laboratory data. A simple analytical injectivity model could approximate some of the features of the field test but was not completely satisfactory.

TX-Mallet (Click Mallet to return to table)

(70068) Conformance Water-Management Team Developments and Solutions on Projects in the Permian Basin

A team was formed to solve field-wide conformance problems in a San Andres (dolomite) unit of the Slaughter Field, Hockley Co., Texas. The team's goal was to increase oil production and decrease production costs by understanding fluid movement through the reservoir. The team was comprised of operating and service company personnel who performed data analysis, and developed engineering and solution designs.

The reservoir conformance team identified, quantified, and fully described field conformance problems. Team members focused on understanding fluid movement through the total reservoir rather than on single wells. They developed a framework of data for designing successful conformance solutions. This framework includes data about the reservoir, completion design, drilling and workover history, production and well-test history, logs, diagnostic analysis, and placement options. The framework serves as a data-collection tool and as a tool for identifying missing data.1

This project involves the following tasks: (1) analyzing approximately 300 wells, (2) identifying conformance candidate (pilot) wells, (3) implementing the pilot wells, (4) analyzing the results from the pilot wells, and (5) applying those results to the rest of the unit. In this project, team members developed the typical data analysis, reservoir and production engineering proposals, and solutions proposals, and also thoroughly reviewed the customer's economic drivers. In these mature units, enhancing recovery and production rates and reducing costs were important factors. Treatments have been placed and analyzed for sweep improvement, CO_2 reduction, and water cycling-breakthroughs.

(36711) From Simulator to Field Management: Optimum WAG Application in a West Texas CO_2 Flood - A Case History

Using field data, the processes by which compositional simulation results are effectively integrated into an active CO_2 flood operating policy are presented as a case history. The economic success or failure of a CO_2 flood often hinges on two basic requirements: effective CO_2-oil contact and displacement, and economic use of CO_2. An inexpensive and effective tool to help achieve these requirements is the use of Water Alternating Gas (WAG) cycles. But how do we use WAG ratios to best displace oil in a timely manner while combatting the effects of reservoir heterogeneity and adverse mobility ratios on sweep efficiency? Reservoir simulation is often used to optimize WAG ratios. The final challenge, however, is to transfer small-scale, homogenized simulation results to the field in such a way as to affect the bottom line; namely decrease operating expenses and increase oil production.

For the Mallet Unit (a West Texas CO_2 flood), compositional simulation results are scaled to the field in accordance to a reservoir characterization. An overall operating philosophy is developed and implemented. A data collection process is developed using integrated software and hardware to provide a basis upon which field surveillance can be conducted.

Finally, overall results are reviewed including accelerated tertiary oil production response and reduced gas processing costs, yielding very favorable project economics.

(20377) Optimization of Waterflood Performance and CO_2-Flood Design Using a Modeling Approach, Mallet Unit, Slaughter Field

The Mallet Unit, located in Cochran and Hockley Counties of west Texas, produces oil from the Permian San Andres dolomite as part of the larger Permian San Andres dolomite as part of the larger Slaughter field. The Mallet Unit was evaluated for waterflood improvement and CO_2 enhanced oil recovery. This paper discusses the modeling approach for optimizing the existing waterflood and designing a CO_2-flood. Four Components were found instrumental in achieving a reliable CO_2-flood design. These four components are: (1) an Equation-of-state accurately matched with representative PVT data, (2) a reliable geological description validated by 23 years of waterflood history, (3) a compositional model which adequately describes the phase behavior and CO_2 displacement mechanism, and (4) a valid scale-up technique for forecasting field-scale CO_2-flood performance from pattern CO_2-flood performance. With these four pattern CO_2-flood performance. With these four Components, oil and CO_2 production response forecasted from the compositional model and scale-up study were found to be in reasonable agreement with the field observation of a near by CO_2-flood. This nearby CO_2-flood has similar geology and fluids. Recommendations for waterflood improvement and CO_2-flood design were made based on both black-oil and compositional simulation results.

(16831) Carbonated Waterflood Implementation and Its Impact on Material Performance in a Pilot Project

Carbonated waterflooding is an enhanced oil recovery process developed in the early 1950's that may have potential application in several West Texas reservoirs. The process consists of saturating injection water with CO_2 in order to swell the remaining oil-in-place, and thereby increase the amount of recoverable oil in a reservoir. The process usually involves less investment and CO_2 demand than miscible CO_2 flooding.

The effects of carbonated waterflooding on equipment material performance were monitored during a two well carbonated water injection pilot test conducted by Amoco Production Company in the Slaughter Field, Hockley County, Texas. Stainless steel and aluminum bronze material showed no deterioration during the test period. However, severe problems were encountered at holidays in the internal plastic coating of carbon steel pipe and fittings. Injection well material performance data and observations are presented to support these findings. In addition, the surface equipment design used to saturate injection water with CO_2 will be presented. No attempt will be made to discuss the impact of carbonated waterflooding on injection well or reservoir performance.

(16830) CO_2 Injection and Production Field Facilities Design Evaluation and Considerations

Many technical papers have been published on CO_2 flooding from a reservoir standpoint; but, few have ever discussed design considerations of field CO_2 production and injection facilities. This paper will present initial design and installation considerations, design criteria, and initial installation problems associated with Amoco's four West Texas CO_2 projects (Slaughter Estate Unit, Central Mallet Unit, Frazier Unit, Wasson ODC Unit). Additionally, design and operational considerations, based on the experience gained from operating the four CO_2 floods during the last two years, will be discussed for use in future CO_2 facility designs.

Equipment problems which have been experienced during operation, modifications which have been made as a result of experience, and recommended changes for future designs will be discussed in this paper. Actual case histories of operations, equipment design, and equipment problems encountered will be presented. The specific areas to be discussed will include: The CO_2 injection system material selection and layout, CO_2 injection wellhead material selection and configuration, CO_2 injection well downhole equipment, producing wellhead pressure and material requirements, flowline and fluid gathering systems, satellite and central tank battery layout and operation, and the gas collection system layout and material selections.

Special considerations will be given to design details and material specifications that are often overlooked, or not considered. The resulting potential problems and failures of these oversights will be discussed.

(12015) Comprehensive Geological and Reservoir Engineering Evaluation of the Lower San Andres Dolomite Reservoir, Mallet Lease, Slaughter Field, Hockley County, Texas

The Mallet Lease, Hockley County, western Texas, produces oil from the Permian San Andres Dolomite as produces oil from the Permian San Andres Dolomite as part of the larger Slaughter Field. The Mallet Lease part of the larger Slaughter Field. The Mallet Lease is being considered for infill drilling and for tertiary recovery. This paper discusses the engineering and geologic basis of the reservoir description that is used in history matching 40 years of primary and secondary performance. Emphasis is given to integration of reservoir description with necessary fluid flow properties needed to match performance and also the use of long term data to insure proper reservoir representation.

There are no discontinuous, isolated portions of the reservoir that would be tapped by infill wells. Most of the remaining oil is located in the tighter portions of the producing intervals which bears on portions of the producing intervals which bears on prospects for infill drilling and tertiary oil recovery. prospects for infill drilling and tertiary oil recovery.

TX-McElroy (Click McElroy to return to table)

(59528) Injection-side Application of MARCIT Polymer Gel Improves Waterflood Sweep Efficiency, Decreases Water-Oil Ratio, and Enhances Oil Recovery in the McElroy Field, Upton County, Texas

This case history will discuss how MARCIT polymer gels were used at injection wells to correct channeling problems in a waterflood, so that additional oil could be swept toward producing wells and recovery improved. As a result of the polymer gel project, oil is up, water is down, and 36,000 to 50,000 barrels of incremental oil have been recovered to date. Project payout was achieved in less than ten months using an oil price of $10 per barrel.

(38910) Modeling of Waterflood in a Vuggy Carbonate Reservoir

A methodology was developed to model and successfully history match the primary and waterflood phases in a 15 well, 100 acre vuggy portion of a carbonate field in west Texas. This method is based on a derived log trace of secondary porosity calculated by subtracting sonic porosity (matrix only) from a core calibrated total porosity transformed from Density and Neutron-logs. Log signatures of vugular intervals were developed by recognizing significant differences in matrix and total porosity. A detailed geostatistical distribution of total porosity was first generated and permeability was assigned using a cloud transform of core data from nearby wells. Two geostatistical distributions of secondary porosity with different correlation lengths were then generated using the developed secondary porosity trace. Vugular zones were assumed to have a secondary porosity of 8% or greater. These models were superimposed on the permeability cube by assigning exceptional high permeability values to the vuggy zones.

Using a general scale up method, the detailed permeability cubes were scaled-up for simulation studies.

The models incorporating vuggy permeability distributions showed a far superior history match of primary and waterflood performance than those without vuggy permeability distributions. Good history match was also obtained on individual well basis. Sensitivity of the match to vuggy zone permeability and correlation length was analyzed. Results from these simulation runs provides insight into the spatial distribution and permeabilities of the vuggy zones.

(24873) Waterflood Improvement in the Permian Basin: Impact of In-Situ Stress Evaluations

Chevron has undertaken waterflood improvement programs in a number of its fields in the Permian Basin that call for increasing well densities and water injection pressures. Waterflood patterns need to be realigned and new wells optimally located to minimize well interference. We evaluated the magnitude and directions of the in-situ stresses in support of waterflood improvement programs in the McElroy Field and North Westbrook Unit, on the western and eastern margin of the Midland Basin, respectively. Rapid production responses to injection and strong, directional floodwater effects occur in WNW-ESE and NE-SW directions in McElroy and North Westbrook, respectively. In-situ stress data confirmed that directional floodwater effects in these oil fields coincided with hydraulic-fracture directions and provided input to subsequent waterflood management programs.

In McElroy Field, waterflood realignment in a line drive to conform to the WNW-ESE trend is ongoing. Where realigned, production responses and reservoir pressures have shown significant and sustained improvement. In North Westbrook, the waterflood was already more or less aligned with the NE-SW trend. Documenting the in-situ stress data and their association with production effects has allowed the engineers to operate and manage the waterflood more effectively. An infill-drilling program was initiated on a 720-acre project area. Well locations were chosen to minimize floodwater channeling between injection and production wells. Of fifteen wells drilled to date, no channeling problems have occurred.

(24184) Phase Behavior Modeling Techniques for Low-Temperature CO_2 Applied to McElroy and North Ward Estes Projects

This paper describes a technique to model the behavior of three phase low temperature CO_2 systems using two phase PVT algorithms, and its application to two field CO_2 projects. An approximate tuning procedure has been developed for using a two phase equation of state to characterize the displacement behavior of CO_2 in the three phase domain. This characterization technique results in good prediction of laboratory slim tube displacement tests and the minimum miscibility pressure (MMP) for both pure and impure CO_2 streams. Laboratory corefloods and field scale displacements can also be modeled to a practical level of accuracy. With this pseudo two-phase representation, complex three-phase flash calculations and the need for four-phase relative permeabilities are avoided.

This approach was used in forecasting the North Ward Estes CO_2 project. Volume of mixing effects characteristic of low temperature CO_2 systems are modeled in a vertical fine resolution geostatistical cross section with a compositional simulator. Reasonable agreement with observed field performance is obtained. An immiscible CO_2 huff-n-puff test at the McElroy field was also modeled, using a 2-D radial compositional model. The cross section was derived from geostatistics. The simulation also provided a good approximation of field observation.

(20120) Waterflood Pattern Realignment at the McElroy Field: Section 205 Case History
A waterflood pattern realignment project in the Grayburg / San Andres McElroy Field is improving the waterflood performance. This paper presents a case history of a 640-acre [259 paper presents a case history of a 640-acre [259 ha] section of the field that was realigned in 1988. Irregular and widely spaced patterns were developed into smaller and more uniform patterns. The results of the realignment are patterns. The results of the realignment are proving the economic viability of realignment proving the economic viability of realignment work at McElroy and are improving reservoir characterization.

(20105) In-Situ Stress Evaluation in the McElroy Field, West Texas
This paper discusses an in-situ-stress evaluation program conducted in the McElroy field in preparation for waterflood realignment. Microfracturing and borehole logging results indicated that the maximum horizontal stress orientation was north-northwest, west-northwest, and north-northwest in the upper, middle, and lower payzone intervals, respectively. Microfracturing proved to be the most reliable and cost-effective technique for in-situ stress evaluation in this heterogeneous reservoir.

(853) Pilot Water Flooding in a Dolomite Reservoir, The McElroy Field
The McElroy field, discovered in 1926, is one of the major oil reservoirs of West Texas. Production is obtained from the Permian Grayburg-San Andres dolomites at an average depth of 3,000 ft. Two gas injection and four waterflood pilots have been conducted in the field. Both of the gas injection projects were unsuccessful because of high free-gas saturations in the reservoir. Three of the pilot water floods have sufficient performance histories to permit thorough evaluations. Pilot I, an inverted seven-spot installed in 1947, and Pilot II, a 20-acre five-spot installed in 1953, have proved the old, better part of the field could be successfully flooded. The best wells in these pilots have produced large volumes of oil at water-oil ratios of approximately one. This performance is thought to be more the result of gravity effects than stratification. Pilot III, two contiguous 40-acre, five-spots, was installed in late 1959 and has proved the floodability of the tight, anhydritic portion of the reservoir. Injectivity problems were encountered but were remedied by increases in pressure. Pilot IV was initiated late in 1959 to determine if the old part of the field could be flooded on wide spacing. It consists of four injection wells closing 160 acres which contain nine producers. There have been some individual well responses; however, interference between injection wells is still one to two years in the future.

TX-Mead Strawn (Click Mead Strawn to return to table)
(17134) Evolution of the Carbon Dioxide Flooding Processes
Carbon dioxide flooding has become one of the major EOR processes in the U.S., with potential recovery of billions of barrels of oil that otherwise would be left as residual in known U.S. reservoirs. Extensive commercial-scale CO_2 projects are under way, and other new projects and expansions are planned for the future. This paper briefly reviews the evolution of the CO_2 flooding processes as they are most commonly applied today. The important features of CO_2 flooding, which have been defined by extensive laboratory research and field testing, are summarized. Included are summaries of (1) early developments in the use of CO_2, (2) oil displacement mechanisms of CO_2, and (3) other factors involved in the design of CO_2 floods-i.e., CO_2 availability, CO_2 injection requirements, mobility control, reservoir conditions, safety, CO_2 reinjection, corrosion, and solids precipitation.

(3103) Carbon Dioxide Test at the Mead-Strawn Field
Core data and production histories from the CO_2 test flood area, compared with similar data obtained from areas that had been water flooded, confirmed the results of laboratory experiments, which had shown that a CO_2 flood recovers 50 to 100 percent more oil than a conventional water flood.

TX-Means (Click to Means (San Andres) return to table)
(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of

waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacings. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(24928) Update of Industry Experience with CO_2 Injection

The main purpose of this paper is to utilize current industry experience to evaluate the performance to date of miscible CO_2 injection projects. Also included is a summary of innovations being implemented by industry to improve recovery from existing CO_2 projects. Experience to date has shown that on balance, CO_2 injection projects have performed better than anticipated and offer a significant opportunity for improving ultimate recovery from existing reserves.

(24111) Prediction of CO_2/Crude Oil Phase Behavior Using Supercritical Fluid Chromatography

In this paper, we describe a method for characterization of crude oils for predictions of phase behavior of CO_2/crude oil mixtures with an equation of state (EOS). The method includes the use of supercritical fluid chromatography (SFC) with CO_2 as the carrier fluid. Pressure-composition diagrams calculated using the Peng-Robinson EOS and this characterization scheme agree well with PVT observations. The advantage of this technique is that it produces predictions of the phase behavior of CO_2/crude oil mixtures with much less experimental effort than is required to perform PVT experiments.

(19783) An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs

In this paper we present the results of a technical and an economic evaluation of waterflood infill drillings in fourteen Clearfork and eleven San Andres carbonate reservoirs in West Texas. The initial waterflood recovery efficiency and the infill drilling waterflood recovery efficiency were estimated from decline curve analyses. The economic analysis was performed to evaluate the relative profitability of the waterflood infill drilling operations.

For Clearfork units, the estimated initial waterflood recovery efficiency ranged from 9.54 to 32.19% of original oil in place (N) with a medium of 17.75%N; and the infill drilling waterflood recovery efficiency ranged from 13.09 to 52.56%N with a medium of 25.53%N. The medium increase in oil recovery by infill drilling was 7.78%N. For San Andres units, the initial waterflood recovery efficiency ranged from 10.68 to 39.03%N with a medium of 19.97%N; and the infill drilling waterflood recovery efficiency ranged from 13.73 to 44.58%N with a medium of 31.82%N. The medium increase in oil recovery by infill drilling was 11.38%N.

A multi-linear regression analysis was used to establish regression models correlating the initial waterflood and the infill drilling waterflood recovery efficiencies to reservoir and process parameters. For the Clearfork units, the process parameters. For the Clearfork units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 20.39%N and 3.19%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 29.25%N and 2.48%N, respectively. The average increase in oil recovery by infill drilling was 8.86%N. For the San

Andres units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 22.09%N and 1. 45%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 32.23%N and 2.73%N, respectively. The average increase in oil recovery by infill drilling was 10.14%N.

Two cases were studied in the economic analyses. Case I economic analysis used past and projected production schedule and economic projected production schedule and economic parameters. For the Clearfork units, the rate of parameters. For the Clearfork units, the rate of return ranged from 18.37% to 125.2% with a mean of 53.3%. The payout ranged from 1.22 years to 6.58 years with a mean of 3.14 years. For the San Andres units, the rate of return ranged from 20.58% to 500.0% with a mean of 157.0%. The payout ranged from 0.36 to 5.43 years with a mean payout ranged from 0.36 to 5.43 years with a mean of 1.77 years.

Case II economic analysis used past and projected production data as though the projects projected production data as though the projects were initiated in January 1988. The base crude oil price of $17.50/STB was assumed in the analyses. For the Clearfork units, the rate of return ranged from 11.41% to 98.80% with a mean of 40.4%. The payout ranged from 1.45 to 6.42 years with a mean of 3.53 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 4.28 years and 3.13 years using $22.50/STB. For the San Andres units, the rate of return ranged from 20.58% to 500.00% with a mean of 157.00%. The payout ranged from 2.36 to 4.91 years with a mean of 2.3 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 2.18 years and 2.00 years using $22.50/STB.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987

Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(17349) Review of the Means San Andres Unit CO_2 Tertiary Project

A full-scale CO_2 miscible tertiary project in the Means San Andres Unit, Andrews County, TX, is expected to result in the additional recovery of more than 38 million STB [6.0 x 10(6) stock-tank m3]. Design, implementation, surveillance, and early performance of the CO_2 project are discussed.

(16854) Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas

This paper presents the results of an economic analysis of infill drilling in 16 carbonate oil reservoirs located in West Texas. The economic analysis included the evaluation of incremental waterflooding recovery over primary and infill drilling recovery over initial waterflooding.

Because of limited field and economic data available for this study, many assumptions were made to complete the economic evaluations. Two major cases of economic evaluation were performed: Case 1 used the past production and economic data to 1986 and the projection of these data from 1986 on to the assumed economic limit, and Case II used the past infill production data as if the projects were initiated in January 1986 and on to the assumed economic limit.

Results showed that about 6811 of the infill drilling projects studied had an infill drilling incremental payout of less than two years with a incremental discounted cash flow rate of greater than 20%. Only 37% of the projects studied had a waterflood incremental economics with the same criteria. Decreasing the well spacing generally decreased the infill drilling incremental payout and increased the incremental cash flow rate of return. As the OOIP/WS (well spacing) increased, the general trend showed an increasing infill drilling incremental net present value.

Results from Case II studies showed that for a $15/STB ($94/m 3) oil price in 1986, about 68% of the infill drilling projects studied had an infill drilling incremental payout of less than two years with an incremental discounted cash flow rate of return greater than 20%. As the OOIP/WS increased, the general trend also showed an increasing infill drilling incremental net present value. When the oil price in 1986 was increased from $15/STB ($94/m 3) to) $25/STB 0157/m 3), the increase " the incremental net present value (INPV) was substantial. For example at a value of 20 for OOIP/WS (Means Field/San Andres), the INPV increased from $76 MM to $122 MM.

(15037) An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units

This paper examines the profitability of past waterflood infill drilling programs. The past waterflood infill drilling programs. The project data is from the Texas Railroad project data is from the Texas Railroad Commission files, and includes large carbonate and sandstone reservoirs such as the Wasson (San Andres) Field and the Big Wells (San Miguel) Field. All of the reservoirs were subject of intensive reservoir engineering and geologic study by the oil companies prior to initiation of the infill drilling project. The permeability of the reservoirs averages 8.8 md and ranges permeability of the reservoirs averages 8.8 md and ranges from .65 md to 27 md. The porosity averages 10% and ranges from 7% to 18.6%. The depths range from 1220 to 1525 meters with the deepest at 2130 meters.

Because of the large capital cost required for drilling and operating additional wells, it was not clear whether the infill drilling programs had recovered enough additional oil to be programs had recovered enough additional oil to be good investments. In spite of the variability of external factors such as the cost of wells and price of oil, all of the projects studied obtained at least an acceptable economic return. the average discounted profit to investment ratio was 2.0, and the average incremental oil per well was 15 thousand cubic meters. Most of per well was 15 thousand cubic meters. Most of the calculated rates of return exceeded 30%. The net present value at 15% after taxes ranged from $580,000 to $32 million dollars. Thus these waterflood infill drilling projects have generally been very successful.

(11987) Design and Operation of a CO_2 Tertiary Pilot: Means San Andres Unit

This paper describes the design, implementation and operation of a CO_2 tertiary pilot in the Means San Andres Unit, Andrews County, Texas. The pilot consisted of five wells on 1.5 acres. Detailed geological studies showed the reservoir to be more heterogeneous than broader studies had indicated. Pilot operations and evaluation were complicated by a dual permeability zone. Special tests to define this interval are described. Evidence of additional oil recovery was shown from both log analysis and fluid samples.

(11023) Infill Drilling To Increase Reserves-Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois

Evaluation of reservoir discontinuity has been used by industry to estimate potential oil recovery to be realized from infill drilling. That this method may underestimate the additional recovery potential is shown by continuity evaluation in a west Texas carbonate reservoir, as infill drilling progressed from 40-acre (162 ´103-m2) wells to 20-acre (81´103-m^2) wells and eventually to 10-acre (40.5´103-m^2) wells. Actual production history from infill drilling in nine fields, including carbonate and sandstone reservoirs, shows that additional oil recovery was realized by improving reservoir continuity with increased well density.

(6739) Improved Techniques for Evaluating Carbonate Waterfloods in West Texas

Detailed studies of three waterfloods in Permian carbonate reservoirs of west Texas resulted in new depletion plans with major operating changes, including infill drilling and pattern modifications. Close coordination of geologic and engineering work produced a consistent approach to the relationship between reservoir description and operations when calculating ultimate recovery.

(3301) Evaluation and Modification of the Means San Andres Unit Waterflood
Following detailed studies, the injection scheme of this unit was expanded to include interior injection as well as the original peripheral injection. The success of the project has borne out the peripheral injection. The success of the project has borne out the fact that a combination of engineering analysis and geological interpretation is far more effective in understanding performance than either study could be by itself.

TX-Mid Cross-Devonian (Click Mid Cross to return to table)
No articles found

TX-North Cowden (Click North Cowden to return to table)
(28385) Integrated Reservoir Characterization: Beyond Tomography
In 1992, there was a collaborative effort in reservoir geophysics involving Amoco, Conoco, Schlumberger and Stanford University in an attempt to delineate variations in reservoir properties of the Grayburg unit in a West Texas CO_2 pilot at North Cowden field. Our objective was to go beyond travel time tomography in characterizing reservoir heterogeneity and flow anisotropy. This effort involved a comprehensive set of measurements to do travel time tomography, reflector imaging, analysis of channel waves, shear wave splitting for borehole stress estimation, seismic anisotropy, combined with 3D surface seismic and sonic log interpretation. Results are to be validated with cores and engineering data by history matching of primary, water and CO_2 injection performance. The implementation of these procedures should provide critical information on reservoir heterogeneities and preferential flow directions.

(27671) Hydrocyclone Separation: A Preferred Means of Water Separation and Handling in Oilfield Production
Hydrocyclone technology has been successfully applied to standard oilfield production separation in the North Cowden Deep Field of West Texas. A hydrocyclone was successfully tested as the primary means of water separation for a high water cut electric submersible pump (ESP) well, thereby eliminating the need for expanding the conventional water separation and handling facilities at the recipient battery. This hydrocyclone system was environmentally and economically preferred over conventional systems. A permanent unit has since been installed. With its feasibility proven, the hydrocyclone has countless applications to standard oilfield production separation; its proper use will substantially reduce capital investment for facilities and lower operating expenses for many oilfield leases.

(25655) Geostatistical Application for Exploration and Development: Porosity Estimation from 3-D Seismic Data Calibrated to Well Data
The geostatistical external drift method is used to integrate 3-D seismic data into a reservoir description and is illustrated with an application on a west Texas Permian Basin interbedded carbonate-clastic reservoir. Seismic reflection amplitudes, calibrated to core and sonic-derived porosity data, supplements sparse well control to estimate interwell porosity.

An extensive well log and core data base was sampled over a small portion of the field covered by a high resolution 3-D seismic survey to mimic scenarios similar to three stages in a reservoir's life: (1) a 7 well case, typical of a late exploration/early appraisal phase; (2) a 14 well case, similar to a development, phase; and (3) a 55 well case (40-acre well spacing), representing a mature production phase.

Spatial interpolation by kriging porosity with and without seismic data are compared. Stochastic (Monte Carlo) simulations are used to evaluate interpolation uncertainty (standard error), a quantity not obtained from kriging. Interpolation uncertainty is greatly reduced when seismic data are integrated into the reservoir description.

(16716) The Effects of CO_2 Flooding on Wettability of West Texas Dolomitic Formations
Reduced water injectivity after CO_2 injection has frequently occurred in West Texas oil fields. One explanation proposed for this phenomenon was a change in rock wettability by the CO_2 and crude oil miscible bank. This paper describes an experimental study to determine the effects Of CO_2 flooding on the wettability of West Texas dolomitic cores.

This study examined the relative permeability characteristics of fresh-state San Andres and Grayburg dolomite core samples before and after passing a crude Oil/CO_2 miscible front through the test core. Changes in the relative permeability characteristics were used to infer the effects Of CO_2 flooding on rock wettability. The cores chosen were intermediate oil wet, intermediate, and intermediate water wet. The results showed that the cores became slightly more water wet. However, this change in wettability was near the limit of statistical confidence. Some data suggests that the tendency to becoming water wet was cause by slight rock dissolution by the CO_2 and brine. Some observations concerning the compatibility of brines used in laboratory core floods with dolomites containing anhydrite are discussed.

(11165) Preliminary Findings from a Study to Perform Automated Metering and Control of Carbon Dioxide Injection with a Liquid Turbine Meter

With the advent of tertiary flood projects utilizing CO_2 as an injection medium, the need to adequately measure and control it becomes imperative for achieving optimum injection to withdrawal ratios. Maintaining an optimum ratio is particularly important in the economic sense considering that the injection medium initially would not be available as a by product of production. Preliminary data compiled from a study to perform automated volumetric metering and injection rate control of CO_2, using the liquid turbine meter is presented in this treatise. Observations of CO_2 flow within a temperature range of 29-104 deg/f and a pressure range of 950-1250 psig are made for two one-inch liquid turbine meters. The compiled data depicts measured turbine meter accuracy variations which may be controlled to within 6% of true flow by correction formulas that may be solved by digital or analog techniques.

(9719) Response of North Cowden and Goldsmith Crudes to Carbon Dioxide Slugs Pushed by Nitrogen

Laboratory studies have been conducted to determine oil recovery of the North Cowden-Grayburg and Goldsmith 5,600-ft [1700-m] Clearfork crudes of west Texas when pushed by CO_2 at various pressures. Studies were made pushed by CO_2 at various pressures. Studies were made at reservoir temperatures of 100 and 111 degrees F [38 and 44 degrees C] for the North Cowden and Goldsmith 5,600-ft [1700-m] crudes, respectively. At these temperatures, it was found that the oil recovery ranged from 57 to 99% as the CO_2 pressure increased from 700 psi to 1,800 psi [4.8 to 12.4 MPa]. Normally the North Cowden crude gave a higher oil recovery throughout the pressure range. In recognition that CO_2 may be in short supply, studies were made of the possibility of using a slug of CO_2 pushed by nitrogen. For the slug tests the CO_2 slugs pushed by nitrogen. For the slug tests the CO_2 slugs ranged from 2.5% to 25% HCPV. All CO_2 slugs were pushed by nitrogen. The oil recovery ranged from pushed by nitrogen. The oil recovery ranged from approximately 60 to 99% over this slug size. The data were obtained in slim-tube equipment ranging from 40 to 100 ft [12 to 30 m] in length.

The miscible bank formed between the CO_2 and the body of the crude oil was observed to be a clear strawcolored liquid. The analyses of the clear liquid and crude oil conclusively demonstrate (1) that the crude oil undergoes a continuous fractionation process when miscibly displaced by CO_2, (2) the need for tong flow tests, and (3) the inability to interpret most PVT cell data in terms of miscibility.

(9364) Solar Powered Injection Controller Utilizing Bottom Hole Pressure Sensing Device

An innovative new water injection controller has been developed which will significantly improve water injection into wells, especially those exhibiting no measurable surface pressure. The new system consists of a motor control valve, turbine meter, injection controller, and bottom hole pressure (BHP) device, with power supplied by a solar pressure (BHP) device, with power supplied by a solar panel, negating the need and added expense of panel, negating the need and added expense of running power to each well. The new system has the capability to monitor well BHP, compare the BHP against a preset value, and adjust the injection rate accordingly. The system will eventually have the capability to run step-rate tests and pressure fall-off tests automatically, as well as perform temperature surveys. Since the unit is installed in the tubing in much the same manner as a wire line tool, no pulling unit expense is incurred.

TX-North Cross (Crossett) *(Click North Cross to return to table)*

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(24210) North Cross (Devonian) Unit CO_2 Flood: Status Report

The North Cross (Devonian) Unit CO_2 flood, Shell's first, began in 1972. While fairly small by West Texas standards, the project provides an example of a successful, mature CO_2 flood. Seventy-eight billion cubic feet (BCF) of pipeline CO_2 have been injected into the reservoir. Recycled produced gas has augmented this to bring cumulative CO_2 injection to 128 BCF or nearly 70% of the hydrocarbon pore volume. Production performance has been excellent. Unit oil production increased from approximately 1400 barrels per day (BOPD) when CO_2 injection began to its peak of over 2600 BOPD in late 1978 before declining gradually to approximately 1900 BOPD by the end of 1991. An estimated 11 million barrels of enhanced oil have been recovered through 1991 and ultimate EOR is expected to double to over 22 million barrels.

(24115) Role of Three-Hydrocarbon-Phase Flow in a Gas Displacement Process

The objective of this work was to identify the role of three-hydrocarbon-phase flow in the displacement of a reservoir oil by light hydrocarbon gas mixtures (methane through n-butane). A compositional simulator capable of handling three nonaqueous phases was used to simulate these one-dimensional displacements. A modified Peng-Robinson equation of state fluid characterization was developed based on several single-contact and multicontact PVT experiments. A compositionally consistent relative permeability formulation was used. The numerical dispersion was controlled to match measured physical dispersion.

Slim tube experiments show that as dilution with lean gas increases, the displacements go from first contact miscible to multicontact miscible to three-phase immiscible to two-phase immiscible. Recovery is high (>85%) for the first three cases and nonmonotonic with dilution. Simulation results mimic experimental slim tube recovery and gas breakthrough behavior qualitatively; especially the increase in oil recovery with increasing methane dilution of the solvent. High oil recoveries in the cases appear to be due to condensation of solvent into the oil resulting in (l) low oil viscosity and (2) effective displacement of oil by the second liquid phase that forms.

(23974) Analysis of Tertiary Injectivity of Carbon Dioxide

The most important conclusions is that the mixing phenomenon due to dispersion, crossflow and viscous instability that models neglect can significantly influence injectivity. The results indicate that three-phase flow of gas, oil and brine needs to be modeled and that, contrary to the conclusions of other investigators, three-phase flow effects can have important influences on injectivity, even when CO_2 is injected above its MMP. In addition, the most sensitive relative permeability parameters for reservoir-scale, tertiary CO_2 flooding conditions in parameters for reservoir-scale, tertiary CO_2 flooding conditions in the presence of correlated permeability heterogeneity are identified. Sensitivity to the relative permeability parameters can also be substantial, even at low permeability contrast. The results presented in this paper are particularly pertinent to the hybrid-WAG displacement process since they provide information about the first cycle of CO_2 injection.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987

Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(17134) Evolution of the Carbon Dioxide Flooding Processes

Carbon dioxide flooding has become one of the major EOR processes in the U.S., with potential recovery of billions of barrels of oil that otherwise would be left as residual in known U.S. reservoirs. Extensive commercial-scale CO_2 projects are under way, and other new projects and expansions are planned for the future. This paper briefly reviews the evolution of the CO_2 flooding processes as they are most commonly applied today. The important features of CO_2 flooding, which have been defined by extensive laboratory research and field testing, are summarized. Included are summaries of (1) early developments in the use of CO_2, (2) oil displacement mechanisms of CO_2, and (3) other factors involved in the design of CO_2 floods-i.e., CO_2 availability, CO_2 injection requirements, mobility control, reservoir conditions, safety, CO_2 reinjection, corrosion, and solids precipitation.

(6390) North Cross (Devonian) Unit CO_2 Flood - Review of Flood Performance and Numerical Simulation Model

Although the North Cross (Devonian) Unit CO_2 flood has not performed as dramatically as predicted, response to CO_2 injection has been encouraging. Sharp, sustained production increases in responding wells and minimal CO_2 breakthrough indicate that CO_2 is displacing oil efficiently. No major operating problems have been encountered so far. CO_2 injectivities have been significantly below initial predictions.

(4737) The Use of Numerical Simulation to Design a Carbon Dioxide Miscible Displacement Project

The prediction of a single-layered, two-dimensional areal model was compared with results from cross-sectional, two-dimensional vertical models. Effects of gravity segregation and existing reservoir heterogeneity were not significant enough to justify use of a three-dimensional model for predicting field behavior of the North Cross (Devonian) Unit CO_2 miscible displacement project in West Texas. Project in West Texas.

A numerical simulation method was used to design a carbon dioxide (CO_2) miscible displacement project in a low-permeability carbonate reservoir. A field history match was obtained as a check on the model's validity. Two-dimensional, vertical (cross-section) models were used to determine the potential effects of high gas saturation at the top of the formation on CO_2 injection profiles and to evaluate the effect of reservoir heterogeneity on sweep efficiency. A two dimensional areal model was used to describe the field's response to CO_2 injection. Using an areal model, various CO_2 injection patterns were simulated and compared, and an inverted patterns were simulated and compared, and an inverted nine-spot was found to be the optimum pattern for this field. Further simulation predictions were conducted to evaluate various schemes of handling produced CO_2-contaminated gas after CO_2 breakthrough. It was found that direct reinjection of the contaminated gas was preferable to separating the CO_2 from the gas or venting the contaminated gas. The project - the North Cross (Devonian) Unit in West Texas - is unlike the classical miscible project in that continuous injection of CO_2 and residue project in that continuous injection of CO_2 and residue gas is planned rather than injection of miscible slugs followed by or alternating with water or dry gas. Injection of CO_2 commenced in April 1972. Actual project performance to date has been encouraging. project performance to date has been encouraging. Reservoir Description

The Crossett field is located at the southern edge of the central basin platform of West Texas. The reservoir is a chalky, siliceous carbonate having 21 percent porosity and 3 md permeability. Fig. 1 shows percent porosity and 3 md permeability. Shown is the gross Devonian reservoir thickness above the water-oil contact. There is no significant water drive present, so the primary recovery mechanism is solution gas drive. The reservoir is limited on the west by truncation caused by the post-Devonian unconformity. The eastern limit of the reservoir is provided by a water-oil contact, and the north and provided by a water-oil contact, and the north and south boundaries are defined by permeability and porosity deterioration. The reservoir is unusually uniform for a carbonate. Also shown is a plot of core permeability and porosity vs. well depth. Properties of the reservoir fluid are also listed. The field contained 53 million STB of oil in place when discovered in 1944. The Crossett field was unitized in 1964 and renamed the North Cross (Devonian) Unit. The purpose of unitization was to implement a gas-injection purpose of unitization was to implement a gas-injection pressure maintenance project. All residue casing head pressure maintenance project. All residue casing head gas was injected into the three up dip gas injection wells shown on Fig. 1. Fig. 3 shows the Unit's production history since unitization. production history since unitization. Residue gas injection would only increase the field's recovery to 19 percent from the expected primary efficiency of 13 percent. With so much oil being left in the reservoir, further supplemental recovery schemes were considered.

TX-North Dollarhide (Click North Dollarhide to return to table)

(27678) North Dollarhide (Devonian) Unit: Reservoir Characterization and CO_2 Feasibility Study

In order to implement a CO_2 flood in the North Dollarhide (Devonian) Unit (NDU). detailed reservoir characterization and engineering studies were prepared using 3-D seismic, classical geology and reservoir engineering. and a fieldwide reservoir simulation. Routine and special core analyses, PVT analyses, and well tests taken during recent development aided in the reservoir and fluid characterizations. A black oil reservoir model matched available production and pressure history of the reservoir, and forecasted future production under water injection and CO= injection using mixing rules developed with the aid of a 1/4 5-spot compositional model. History matching presented a special challenge since Devonian and uphole Clearfork production was commingled between late 1970 and 1990, and therefore actual Devonian production and pressures were not implicitly known.

TX-North Farnsworth (Click North Farnsworth to return to table)

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

TX-North Hansford Cherokee (Click North Hansford Cherokee to return to table)

No articles found

TX-North Van Rueder (Click North Van Rueder to return to table)

No articles found

TX-North Ward Estes (Click North Ward Estes to return to table)

(71496) Physical Effects of WAG Fluids on Carbonate Core Plugs

It is a given that carbonate mineral dissolution and deposition occur in a formation in geologic time and are expected to some degree in carbon dioxide (CO_2) floods. Water-alternating-gas (WAG) core flood experiments conducted on limestone and dolomite core plugs confirm that these processes can occur over relatively short time periods (hours to days) and in close proximity to each other.

(30729) An Overview of the North Ward Estes CO_2 Flood

A CO_2 pattern flood was initiated in a west Texas (Permian Basin), sandstone reservoir as a tertiary recovery process in 1989. This paper is an overview of the development and management of the North Ward Estes CO_2 Flood. The primary objective of managing the CO_2 flood has been to maximize oil recovery for maximum profitability. This has been accomplished by maintaining a consistent water-alternating-gas (WAG) process, optimizing CO_2 utilization, and maintaining a proper balance between patterns. Reservoir modeling, which is emphasized in this paper, has also been critical in the development and management of this flood.

(24643) CO_2 Foam Field Trial at North Ward-Estes

A CO_2 foam field trial was conducted in the North Ward-Estes field in Texas to evaluate the effectiveness of foam in improving CO_2 sweep efficiency. This paper describes the design, results, and analysis of foam treatment with emphasis on the design methodology of applying foam in grossly heterogeneous reservoirs, characterized by uneven areal and vertical sweep in most patterns.

Over a period of nearly two years, foam was emplaced into an injector four times by alternately injecting CO_2 and surfactant solution, and followed by continuous CO_2 injection after each emplacement. Foam was generated in situ, which reduced CO_2 injectivity by 40 to 85%. Gas production in the problem producer decreased dramatically, while gas and oil production in other offset producers increased, indicating areal diversion. Vertical diversion also occurred, as evidenced by significant increase in oil production in the problem producer, where tertiary oil response had peaked prior to the foam treatment.

The field test shows that a property designed foam treatment can significantly improve the CO_2 sweep efficiency and be economically successful. The methodology developed in the design and analysis of the foam test may be applied to other conformance improvement processes.

(24184) Phase Behavior Modeling Techniques for Low-Temperature CO_2 Applied to McElroy and North Ward Estes Projects

This paper describes a technique to model the behavior of three phase low temperature CO_2 systems using two phase PVT algorithms, and its application to two field CO_2 projects.

An approximate tuning procedure has been developed for using a two phase equation of state to characterize the displacement behavior of CO_2 in the three phase domain. This characterization technique results in good prediction of laboratory slim tube displacement tests and the minimum miscibility pressure (MMP) for both pure and impure CO_2 streams. Laboratory corefloods and field scale displacements can also be modeled to a practical level of accuracy. With this pseudo two-phase representation, complex three-phase flash calculations and the need for four-phase relative permeabilities are avoided.

This approach was used in forecasting the North Ward Estes CO_2 project. Volume of mixing effects characteristic of low temperature CO_2 systems are modeled in a vertical fine resolution geostatistical cross section with a compositional simulator. Reasonable agreement with observed field performance is obtained. An immiscible CO_2 huff-n-puff test at the McElroy field was also modeled, using a 2-D radial compositional model. The cross section was derived from geostatistics. The simulation also provided a good approximation of field observation.

(20702) Converting Wells in a Mature West Texas Field for CO_2 Injection

This paper deals with the planning, special equipment considerations and operations necessary to convert 165 water injection wells to CO_2 injectors that will function through at least the end of the century. The paper will be divided into two parts: 1) the planning/engineering aspects (reviewing wellhead, packer, and tubular selection), 2) procedural operation highlights (fishing, open hole clean out, casing evaluation and repair, stimulation, liner running practices, wellhead replacement, packer setting, and the reworking of tubulars). A case history approach has been used to analyze the success or failure of the various methods and techniques employed in this project. All 165 wells were converted as of project. All 165 wells were converted as of March 29, 1989.

(20138) Reservoir Management: A Synergistic Approach

Because of the complexities and varied areas of expertise involved in making a primary, secondary, or enhanced recovery project successful, it has become necessary to adopt a team approach for reservoir management. Until the early 1970s, reservoir engineering was considered the only item of technical importance in the management of a reservoir. However, after understanding the value of geology, this no longer holds true. The synergism provided by the interaction between geology and reservoir engineering has been quite successful, but the reservoir management has generally failed to recognize the value of other disciplines, e.g. production operations, drilling, and different engineering functions.

This paper provides information on the treatment of reservoir management as a SYSTEM. The System consists of: 1) reservoir characterization, 2) creation and operation of wells, 3) surface processing of the fluids, and 4) fluids and their processing of the fluids, and 4) fluids and their behavior in the reservoir. These must be considered as interrelated parts of a unified system.

A reservoir management model involving interdisciplinary functions is discussed in this paper. Also, the success of this model in paper. Also, the success of this model in designing and implementing the North Ward Estes CO_2 project, Ward/Winkler County, Texas, is discussed project, Ward/Winkler County, Texas, is discussed in detail. This reservoir management approach has yielded a better design and installation of this CO_2 project. In addition, it has resulted in successful workovers, identification of waterflood improvements, and better plans for future CO_2 projects. projects. A team building approach, involving "in-house" reservoir management forums/workshops, has also been employed. The main objective of the workshops has been to facilitate communication among engineering, geology, geophysics, and operations staff. Synergistic recommendations for project improvement have been a mutual outgrowth of these forums.

(20099) Converting Wells in a Mature West Texas Field for CO_2 Injection
This paper deals with the planning, special equipment considerations, and operations necessary to convert 165 water injection wells to CO_2 injectors that will function through at least the end of the century. The paper is divided into two parts: planning and engineering (wellhead, packer, and tubular selection) and procedural operation highlights (fishing, openhole cleanout, casing evaluation and repair, stimulation, liner running, wellhead replacement, packer setting, and the reworking of tubulars). A case-history approach was used to analyze the success or failure of the various methods and techniques used in this project. All 165 wells were converted as of March 29, 1989. project. All 165 wells were converted as of March 29, 1989.

(19654) Design of a Major CO_2 Flood, North Ward Estes Field, Ward County, Texas
The reservoir engineering aspects of the design of a major west Texas CO_2 flood are presented. The design included a detailed fieldwide geologic study, a CO_2 injectivity test, laboratory work, and reservoir simulation. CO_2 flooding is predicted to recover an additional 8% of the original oil in place (OOIP).

(17281) Optimization of Fracture Stimulation within the North Ward Estes Field
An investigation was initiated to optimize final sand concentrations and profitability in refracturing the North Ward Estes Field in Ward County, Texas.

This study involved the construction of a fracture enhanced production model. The model relates the final fracture width to the associated productivity increase. The fracture model data was utilized to determine the economic performance as a function of final sand concentration, accounting for operating expenses.

The simple mathematical procedure presented will aid the design engineer to quickly predict the average fracture width, frac fluid volume and total sand requirement.

(9711) Fireflooding a High-Gravity Crude in a Watered-Out West Texas Sandstone
This paper describes the results, operational problems encountered, and the ongoing technical evaluation of an in-situ combustion pilot project in the North Ward-Estes field in Ward County, TX (Fig. 1). This sandstone reservoir was discovered in 1929 and has been under waterflood since 1955. Even though the reservoir characteristics were marginal in comparison with the screening criteria for in-situ combustion, laboratory tests indicated that this process could be viable.

(5831) Alkaline Waterflooding: Design and Implementation of a Field Pilot
A field trial of caustic waterflooding in a Queen sand lens in the North Ward-Estes field is described. Comparison of results with projections for a conventional waterflood, while uncertain, indicate that about 25 percent more oil was produced. Operational problems are discussed.

(1147) Reinjection of Large Volumes of Produced Water in Secondary Operations
A study was made of the operating performance histories of a pressure-maintenance and four waterflood projects in the Permian Basin area, where large volumes of produced water have been reinjected into the producing formations. The projects reviewed include a wide range of characteristics: (1) open and closed water systems, (2) volumes of reinjected water froth 2,200 to 12,500 B/D, (3) sand and limestone formations, (4) depths of 1.300 to 6,750 ft. (5) average permeabilities from 17 to 275 md, (6) bare and protected facilities, and (7) 10- to 50-year project life. Each project exhibited performance data which indicated that reinjection of large volumes of produced water provides a good source of injection fluid, results in practical and prudent salt water disposal and, in many cases, results in conservation of fresh water for future domestic needs.

TX-Reeves (Click Reeves to return to table)
No articles found

TX-Reinecke (Click Reinecke to return to table)
(59717) A Pulsed Neutron Analysis Model Carbon Dioxide Floods: Application to the Reinecke Field, West Texas
Rienecke field is one of a series of fields in the Horseshoe Atoll of the Midland Basin. This carbonate reservoir has fairly good lateral and vertical continuity and is confined in a dome-like structure. A gravity-stable crestal carbon-dioxide flood was begun in 1997 by injection into five wells at the high point of the structure. Pulsed-neutron logs run through casing provide a method to monitor reservoir dynamics and locate oil production targets.

The first step in developing a cased-reservoir analysis model is to estimate the carbon dioxide content. This is done by correlation of the cased-hole neutron and density porosities from the pulsed-neutron system. In developing a three-phase saturation model (oil, water, carbon dioxide)the effects of the carbon dioxide on the oil and water saturation measurements must be determined. Computer simulations of tool response are utilized in conjunction with field data to develop the model and the uncertainties in the saturations.

An example log and analysis demonstrate the capabilities of the reservoir analysis model. The analysis results are compared to production and historical data for the field.

(56882) Use of Full-Field Simulation to Design a Miscible CO_2 Flood
A study using full-field reservoir modeling optimized the design of a miscible CO_2 flood project for the Sharon Ridge Canyon Unit. The study began with extensive data gathering in the field and building a full-field three-dimensional geologic model. A full-field simulation model with relatively coarse gridding was subsequently built and used to history match the waterflood. This waterflood model highlighted areas in the field with current high oil saturations as priority targets for CO_2 flooding and generated a forecast of reserves from continued waterflooding. Predictions for the CO_2 flood used an in-house four-component simulator (stock tank oil, solution gas, water, CO_2. A full-field CO_2 model with more finely gridded patterns was built using oil saturations and pressures at the end of history in the waterflood model. The CO_2 model identified the best patterns for CO_2 flooding and was instrumental in selecting a strategy for sizing the initial flood area and in determining the size, location, and timing of future expansions of the CO_2 flood.

(56524) Spatial Distribution of Oil and Water in Horizontal Pipe Flow
This paper reports a series of experiments to quantify the spatial distribution and identify the flow pattern of liquid-liquid flow in a horizontal 25.4mm (nominal one-inch) tube. Experimental results are presented for Kerosene (EXXOL D80) and tap water at room temperature. Two different measurement techniques (a high frequency impedance probe and a gamma densitometer system) were applied for measuring the volume fraction distribution across the tube and to obtain tomographic results for phase distribution. The

use of the gamma densitometer system to obtain the tomographic results in liquid-liquid co-current flow is believed to be the first in this field. These methods are more precise than other techniques such as visualization and help to distinguish certain differences in flow patterns for different superficial velocities and liquid fractions. The two sets of measurements were compared and it was concluded that the gamma densitometer system was a more reliable method to measure the volume fraction. Two important phenomena in liquid-liquid flow were observed:

a) Oil encapsulation by water at low mixture velocity.
b) Droplets concentrated at the center of the pipe in the dispersed flow regime. Some possible explanations are given regarding these phenomena.

TX-Robertson (Click Robertson to return to table)

(Click Robertson to return to table)

(70034) Improved Permeability Estimates in Carbonate Reservoirs Using Electrofacies Characterization: A Case Study of the North Robertson Unit, West Texas

We propose a simple and cost-effective approach to obtain permeability estimates in heterogeneous carbonate reservoirs using commonly available well logs. Our approach follows a two-step procedure. First, we classify the well log data into electrofacies types. This classification does not require any artificial subdivision of the data population but follows naturally based on the unique characteristics of well log measurements reflecting minerals and lithofacies within the logged interval. A combination of principal component analysis, model-based cluster analysis and discriminant analysis is used to identify and characterize electrofacies types. Second, we apply non-parametric regression techniques to predict permeability using well logs within each electrofacies.

Our proposed method has been successfully applied to the North Robertson Unit (NRU) in Gaines county, west Texas. Previous attempts to derive permeability correlations at the NRU have included rock type identification using thin section and pore geometry analysis that can sometimes be expensive and time-consuming. The proposed approach resulted in improved permeability estimates leading to an enhanced reservoir characterization and can potentially benefit both daily operations and reservoir simulation efforts. The successful field application demonstrates that the electrofacies classification used in conjunction with sound geologic interpretation can significantly improve reservoir descriptions in complex carbonate reservoirs.

(68801) Neural-Network Approach to Predict Well Performance Using Available Field Data

Accurate prediction of future well performance is of great importance for petroleum reservoir management. This paper presents a practical neural network approach to predict existing and infill oil well performance using available filed data, such as well production history and well configuration information. It serves as a practical, cost-effective and robust tool for oilfield production and management. Well production, well spacing and the time-dependent information are used to train the neural network. The time-dependent information of wells are incorporated in a manner of time series for establishment of neural network. After the neural network is established, it is used to predict future performance of existing and infill wells. No reservoir data is currently used in the establishment of neural network, therefore it can predict well production performance in absence of reservoir data. Primary production of two data sets (each has 9 wells) in North Robertson Unit located in west Texas was tested using this approach. The results demonstrate that this approach is powerful in rapid projection of existing wells' future performance, as well as the performance prediction of infill drilling wells.

(62557) Swept Volume Calculations and Ranking of Geostatistical Reservoir Models Using Streamline Simulation

Geostatistical techniques are increasingly being used for modeling reservoir heterogeneity and assessment of uncertainty in performance predictions. Although a large number of stochastic reservoir models or realizations may be generated, in practice only a small fraction can be considered for comprehensive flow simulations. This can be done through a ranking process. Several papers have been published in the literature on ranking of realizations. However, a consistent and generally applicable set of criteria for model ranking still remains unclear.

In this paper we propose a connectivity criterion based on the streamline time-of-flight and use this criterion to rank geostatistical realizations for detailed flow simulation purposes and risk assessment. Because time-of-flights reflect fluid front propagation at various times, the connectivity in the time-of-flight provides us with a direct measure of volumetric sweep efficiency for arbitrary heterogeneity and well configuration. We show that the proposed connectivity criterion exhibits strong correlation with waterflood recovery and thus, can be used for ranking stochastic reservoir models. Unlike permeability connectivity which is a static measure independent of the flow field, the time-of-flight connectivity rigorously accounts for the interaction between the flow field and the underlying heterogeneity.

Our proposed approach has been applied to synthetic as well as field examples. Synthetic examples are used to validate the sweep efficiency calculations using the streamline time-of-flight connectivity criterion by comparison with analytic solutions and published correlations. These examples also demonstrate the superiority and effectiveness of the ranking criterion over existing methods. The field example is from the North Robertson Unit, a low permeability carbonate reservoir in west Texas. Our example includes multiple patterns consisting of 27 producers and 15 injectors and illustrates the feasibility of the approach for large-scale field applications.

(59715) Tiltmeter Hydraulic Fracture Mapping in the North Robertson Field, West Texas

This paper presents both downhole and surface tiltmeter hydraulic fracture mapping results of five fracture treatments (in two wells) in the Clearfork formation located in the North Robertson Field, West Texas. This field is under waterflood and both injectors and producers are generally fracture treated in three stages at depths of roughly 6,000 to 7,100 feet. Surface tiltmeter mapping was performed on all five treatments to determine hydraulic fracture azimuth and dip. Downhole tiltmeter mapping was performed on 2 treatments in one well to determine the fracture geometry (height and length). In addition, other diagnostic technologies such as fracture modeling and radioactive tracers were used and their results and conclusions are discussed in conjunction with tiltmeter mapping. Understanding hydraulic fracture growth is of critical importance for evaluating well placement and the risk of communication between producers and injectors and to assess fracture staging, perforating and well performance issues.

(35433) Flow Unit Characterization of a Shallow Shelf Carbonate Reservoir: North Robertson Unit, West Texas

A model is developed of a heterogeneous carbonate reservoir based fundamentally on measurement of pore geometrical parameters. Pore level reservoir modeling results in improved accuracy in the prediction of rock types, permeability and identification of flow units. Pore geometrical attributes are integrated with wireline log data to allow for first, log-based identification of intervals of rock with different capillary characteristics and second, field-wide, log-based prediction of permeability. Twelve hydraulic flow units are identified through integration of data concerning rock type distribution. and depositional environments. Maps of permeability thickness (kH) for each flow unit reveal significant stratigraphic compartmentalization. Future development drilling using uniform well spacing patterns is not appropriate. The location and design of infill drilling patterns should be geologically targeted for prudent, cost-effective field development.

(27668) Improved Reservoir Management With Water Quality Enhancement at the North Robertson Unit

The quality of injection waters used in any new or existing waterflood or EOR process should be considered as a critical component of reservoir management and surveillance programs. Despite decades of industry experience with recovery processes utilizing water in the Permian Basin (and most other major oil producing basins of the world), water quality is an often neglected aspect of reservoir management programs. Consequently, severe injectivity and operational problems are frequently experienced.

This paper describes a case study of water quality control for the Clearfork and Glorieta reservoirs (Permian age) of the North Robertson Unit (NRU) located in the Permian Basin of West Texas. A cost-effective surveillance program for the timely identification and treatment of potential water quality control problems has been designed and implemented. Integration of geological and reservoir parameters, which are crucial to ensure the realization of optimal reservoir performance and operational objectives, is highlighted.

(19783) An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs

In this paper we present the results of a technical and an economic evaluation of waterflood infill drillings in fourteen Clearfork and eleven San Andres carbonate reservoirs in West Texas. The initial waterflood recovery efficiency and the infill drilling waterflood recovery efficiency were estimated from decline curve analyses. The economic analysis was performed to evaluate the relative profitability of the waterflood infill drilling operations.

For Clearfork units, the estimated initial waterflood recovery efficiency ranged from 9.54 to 32.19% of original oil in place (N) with a medium of 17.75%N; and the infill drilling waterflood recovery efficiency ranged from 13.09 to 52.56%N with a medium of 25.53%N. The medium increase in oil recovery by infill drilling was 7.78%N. For San Andres units, the initial waterflood recovery efficiency ranged from 10.68 to 39.03%N with a medium of 19.97%N; and the infill drilling waterflood recovery efficiency ranged from 13.73 to 44.58%N with a medium of 31.82%N. The medium increase in oil recovery by infill drilling was 11.38%N.

A multi-linear regression analysis was used to establish regression models correlating the initial waterflood and the infill drilling waterflood recovery efficiencies to reservoir and process parameters. For the Clearfork units, the process parameters. For the Clearfork units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 20.39%N and 3.19%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 29.25%N and 2.48%N, respectively. The average increase in oil recovery by infill drilling was 8.86%N. For the San Andres units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 22.09%N and 1. 45%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 32.23%N and 2.73%N, respectively. The average increase in oil recovery by infill drilling was 10.14%N.

Two cases were studied in the economic analyses. Case I economic analysis used past and projected production schedule and economic projected production schedule and economic parameters. For the Clearfork units, the rate of parameters. For the Clearfork units, the rate of return ranged from 18.37% to 125.2% with a mean of 53.3%. The payout ranged from 1.22 years to 6.58 years with a mean of 3.14 years. For the San Andres units, the rate of return ranged from 20.58% to 500.0% with a mean of 157.0%. The payout ranged from 0.36 to 5.43 years with a mean payout ranged from 0.36 to 5.43 years with a mean of 1.77 years.

Case II economic analysis used past and projected production data as though the projects projected production data as though the projects were initiated in January 1988. The base crude oil price of \$17.50/STB was assumed in the analyses. For the Clearfork units, the rate of return ranged from 11.41% to 98.80% with a mean of 40.4%. The payout ranged from 1.45 to 6.42 years with a mean of 3.53 years. A sensitivity analysis revealed that the average payout using \$12.50/STB was 4.28 years and 3.13 years using \$22.50/STB. For the San Andres units, the rate of return ranged from 20.58% to 500.00% with a mean of 157.00%. The payout ranged from 2.36 to 4.91 years with a mean of 2.3 years. A sensitivity analysis revealed that the average payout using \$12.50/STB was 2.18 years and 2.00 years using \$22.50/STB.

(16854) Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas

This paper presents the results of an economic analysis of infill drilling in 16 carbonate oil reservoirs located in West Texas. The economic analysis included the evaluation of incremental waterflooding recovery over primary and infill drilling recovery over initial waterflooding.

Because of limited field and economic data available for this study, many assumptions were made to complete the economic evaluations. Two major cases of economic evaluation were performed: Case 1 used the past production and economic data to 1986 and the projection of these data from 1986 on to the assumed economic limit, and Case II used the past infill production data as if the projects were initiated in January 1986 and on to the assumed economic limit.

Results showed that about 6811 of the infill drilling projects studied had an infill drilling incremental payout of less than two years with a incremental discounted cash flow rate of greater than 20%. Only 37% of the projects studied had a waterflood incremental economics with the same criteria. Decreasing the well spacing generally decreased the infill drilling incremental payout and increased the incremental cash flow rate of return. As the OOIP/WS (well spacing) increased, the general trend showed an increasing infill drilling incremental net present value.

Results from Case II studies showed that for a $15/STB ($94/m 3) oil price in 1986, about 68% of the infill drilling projects studied had an infill drilling incremental payout of less than two years with an incremental discounted cash flow rate of return greater than 20%. As the OOIP/WS increased, the general trend also showed an increasing infill drilling incremental net present value. When the oil price in 1986 was increased from $15/STB ($94/m 3) to) $25/STB 0157/m 3), the increase " the incremental net present value (INPV) was substantial. For example at a value of 20 for OOIP/WS (Means Field/San Andres), the INPV increased from $76 MM to $122 MM.

(15568) Quantitative Analysis of Infill Performance: Robertson Clearfork Unit
This study analyzed the results of 218 infill wells drilled in the Robertson Clearfork Unit (RCU), Gaines County, TX. This program increased ultimate recovery by more than 23 million bbl [3.7´106 m3]. The individual well performance, as a function of reservoir continuity, was analyzed quantitatively with pressure correlations, numerical analyses, and geologic study.

(15037) An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units
This paper examines the profitability of past waterflood infill drilling programs. The past waterflood infill drilling programs. The project data is from the Texas Railroad project data is from the Texas Railroad Commission files, and includes large carbonate and sandstone reservoirs such as the Wasson (San Andres) Field and the Big Wells (San Miguel) Field. All of the reservoirs were subject of intensive reservoir engineering and geologic study by the oil companies prior to initiation of the infill drilling project. The permeability of the reservoirs averages 8.8 md and ranges permeability of the reservoirs averages 8.8 md and ranges from .65 md to 27 md. The porosity averages 10% and ranges from 7% to 18.6%. The depths range from 1220 to 1525 meters with the deepest at 2130 meters.

Because of the large capital cost required for drilling and operating additional wells, it was not clear whether the infill drilling programs had recovered enough additional oil to be programs had recovered enough additional oil to be good investments. In spite of the variability of external factors such as the cost of wells and price of oil, all of the projects studied obtained at least an acceptable economic return. the average discounted profit to investment ratio was 2.0, and the average incremental oil per well was 15 thousand cubic meters. Most of per well was 15 thousand cubic meters. Most of the calculated rates of return exceeded 30%. The net present value at 15% after taxes ranged from $580,000 to $32 million dollars. Thus these waterflood infill drilling projects have generally been very successful.

(11023) Infill Drilling To Increase Reserves- Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois
Evaluation of reservoir discontinuity has been used by industry to estimate potential oil recovery to be realized from infill drilling. That this method may underestimate the additional recovery potential is shown by continuity evaluation in a west Texas carbonate reservoir, as infill drilling progressed from 40-acre (162 ´103-m2) wells to 20-acre (81´103-m2) wells and eventually to 10-acre (40.5´103-m2) wells.

Actual production history from infill drilling in nine fields, including carbonate and sandstone reservoirs, shows that additional oil recovery was realized by improving reservoir continuity with increased well density.

(6739) Improved Techniques for Evaluating Carbonate Waterfloods in West Texas

Detailed studies of three waterfloods in Permian carbonate reservoirs of west Texas resulted in new depletion plans with major operating changes, including infill drilling and pattern modifications. Close coordination of geologic and engineering work produced a consistent approach to the relationship between reservoir description and operations when calculating ultimate recovery.

(4064) Efficient Removal of Oxygen in a Waterflood by Vacuum Deaeration

A one-stage vacuum deaeration process with supplemental gas stripping is being used to reduce the oxygen content of about 40,000 barrels per day of source water to 0.05 ppm or less for per day of source water to 0.05 ppm or less for use in the Robertson Waterflood near Seminole, Texas. The vacuum deaeration process is based on the reduced solubility of oxygen in water at reduced pressure and oxygen content of equilibrium vapors. Addition of an inert gas to the contact tower of a vacuum deaeration process further reduces the concentration of oxygen in equilibrium vapors and thereby the dissolved oxygen in the treated waters. The Robertson plant is mechanically simple and fully automated. plant is mechanically simple and fully automated. The water flows through a packed tower to a treated water surge tank. Water from the surge tank is pumped to waterflood injection wells. A vacuum down to 1.0 inch of mercury absolute is supplied to the contactor by a water sealed pump. The contactor is elevated to provide pump. The contactor is elevated to provide gravity flow into the surge tank. Flow rates are controlled relative to the level in the surge tank to equal the demand of downstream injection pumps.

In operation, the one-stage vacuum deaeration alone reduces the oxygen content of the water to approximately 0.17 ppm. Addition of 0.1 cubic foot of natural gas per barrel of water further reduces the oxygen content to 0.05 ppm or less. The inlet water contains 20 ppm carbon dioxide and some calcium at a pH of 7.4. In this case, partial removal of the carbon dioxide with increase in pH to 7.7 has not caused any carbonate scaling. The corrosivity of the inlet water is being reduced from 14 mils per year (mpy) to 1.6 mpy. The plant has operated essentially maintenance free at a treating cost of 0.17 mils per barrel.

TX-Rose City (North and South) *(Click Rose City to return to table)*

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TX-SACROC *(Click SACROC to return to table)*

(56882) Use of Full-Field Simulation to Design a Miscible CO_2 Flood

A study using full-field reservoir modeling optimized the design of a miscible CO_2 flood project for the Sharon Ridge Canyon Unit. The study began with extensive data gathering in the field and building a full-field three-dimensional geologic model. A full-field simulation model with relatively coarse gridding was subsequently built and used to history match the waterflood. This waterflood model highlighted areas in the field with current high oil saturations as priority targets for CO_2 flooding and generated a forecast of reserves from continued waterflooding. Predictions for the CO_2 flood used an in-house four-component simulator (stock tank oil, solution gas, water, CO_2. A full-field CO_2 model with more finely gridded patterns was built using oil saturations and pressures at the end of history in the waterflood model. The CO_2 model identified the best patterns for CO_2 flooding and was instrumental in selecting a strategy for sizing the initial flood area and in determining the size, location, and timing of future expansions of the CO_2 flood.

(35359) SACROC Unit Carbon Dioxide Flood -- Multidisciplinary Team Improves Reservoir Management and Decreases Operating Costs

In 1992, the economic viability of the SACROC Unit was somewhat uncertain. At that time, a multidisciplinary team was formed to improve operational efficiencies and reservoir performance. Better understanding of reservoir geology from detailed biostratigraphic analysis provided the framework to make effective changes. This paper discusses operational efficiency and reservoir exploitation projects implemented by the team.

(27762) A Probabilistic Forecasting Method for the Huntley CO_2 Projects

Two words describe our past approach to miscible CO_2 economic forecasting: deterministic and optimistic. In order to assess the Huntley CO_2 projects more probabilistically and realistically, a team was formed. The team identified five primary areas of risk that are specific to CO_2 projects. The team used judgment, experience, and historic information to assign probability distributions to these areas. Monte Carlo simulation was then used to calculate the distribution of economic outcomes. The mean values of the resulting economic indicators were 20% to 36% below the previously calculated deterministic solutions. This paper describes the method that the team developed, the distributions that were used, what risks were excluded and why, and the resources that were used.

(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs

Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacings. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(24928) Update of Industry Experience with CO_2 Injection

The main purpose of this paper is to utilize current industry experience to evaluate the performance to date of miscible CO_2 injection projects. Also included is a summary of innovations being implemented by industry to improve recovery from existing CO_2 projects. Experience to date has shown that on balance, CO_2 injection projects have performed better than anticipated and offer a significant opportunity for improving ultimate recovery from existing reserves.

(19023) A New Approach to SACROC Injection Well Testing

Every year numerous pressure transient surveys (falloffs) are conducted on SACROC Unit injection wells with the intent of determining the average reservoir pressure for the entire field. The current analysis methods such as Horner and the Miller, Dyes and Hutchinson (MDH) provide an accurate means of determining permeability (k) and skin (s), however the pattern average reservoir permeability (k) and skin (s), however the pattern average reservoir pressure (p) calculation becomes questionable. This is attributed pressure (p) calculation becomes questionable. This is attributed to the uncertainty of total compressibility (ct) and drainage area (A) especially in a CO_2 water-alternating-gas (WAG) flood.

The approach discussed here incorporates the Muskat method to determine these unknowns and apply the results to the Horner analysis. This procedure is intended for mature floods where the pressure at the procedure is intended for mature floods where the pressure at the well boundary remains reasonably constant under balanced single phase fluid pattern injection and production. The application of this method is illustrated by two example falloff tests from the SACROC Unit.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987

Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(17321) Definitive CO_2 Flooding Response in the SACROC Unit

A substantial increase in oil production resulting from CO_2 flooding has been clearly identified in two multi-pattern areas of the SACROC Unit. Analysis of the two areas permitted the identification of oil response to CO_2 injection with greater accuracy than has previously been possible at SACROC. The areas include the 600 acre [2.43 x 10 (6) m^2] Four Pattern Area (4PA) and the 2700 acre [10.93 x 10 (6) m^2) Seventeen Pattern Area (17PA). Located in the Kelly-Snyder Field of Scurry County, Texas, the 50,000 acre [202.3 x 10 (6) m^2] SACROC Unit is the world's largest CO_2 miscible flooding project.

The 4PA encompasses 24 wells arranged in four contiguous inverted 9-spot injection patterns. The area has been on pattern waterflood since 1972 and was at a 95 percent producing water cut when CO_2 water-alternating-gas (WAG) injection was commenced in June 1981. An approximate 30% hydrocarbon pore volume (HPV) of CO_2 was injected over a 5-year period at WAG ratios ranging from two to eight. CO_2 injection ceased in May 1986 and the area has been on continuous water injection since that time. Incremental oil recovery attributable to CO_2 injection is estimated currently to be at least 9% of the original oil in place (OOIP). This represents an estimated cumulative CO_2 utilization of 9.5 Mft3 per barrel of incremental oil [1692 m^3/m^3].

Also on pattern waterflood since the early seventies, the Seventeen Pattern Area has exhibited an approximate 5% OOIP recovery after injecting 17% cumulative HPV CO2. CO2-WAG flooding in the 17PA began in May 1981. Currently, the cumulative CO2 utilization is estimated to be 9.7 Mft^3 per barrel of incremental oil [1728 m^3/m^3].

This paper examines the methods used to determine CO_2 mobilized oil response, describes how the effects of workovers and other "normal" field operations were accounted for, and evaluates the influence of activities in patterns adjacent to the study areas.

(15916) Surface Processing of Carbon Dioxide in EOR Projects

During the past few years there has been a rapid increase in the use of CO_2 to improve the recovery of crude oil from underground reservoirs. Its effectiveness has been well documented. The use of CO_2 for EOR started with the injection of CO_2 at the SACROC Unit in 1972 and by early 1986, there were 66 active projects. Several more are being built or planned. Although the recent drop in oil price has caused some projects to be deferred, in the long term, CO_2 is expected to continue to play a significant role in EOR.

CO_2 can be obtained from natural underground reservoirs or as a byproduct from power plants or chemical facilities, in most cases; it must undergo expensive purification before pipelining or reservoir injection: it must be dried, treated to remove H_2S and other contaminants, and stripped of hydrocarbons. To meet these needs, conventional processes had to be modified and new processes developed to handle CO_2'S unique physical properties. Its density, phase behavior, corrosion characteristics, and chemical properties are quite different from those of the more properties are quite different from those of the more usual gas processing feedstocks. What follows is a discussion of the properties of CO_2 and how they affect the selection and design of surface processing facilities.

(14923) Phase Equilibria in the SACROC Oil/CO_2, System

Phase-equilibrium measurements on SACROC oil/CO, mixtures show this system to display liquid/vapor (L/V) criticality at a composition of 60 mol% Co, with a pressure of 2,560 psia [17.65 MPa] and a temperature of 131deg.F [328.15 K]. In the vicinity of the critical region. liquid quality lines show three- and four-fold pressure multiplicities for a given composition. These multiplicities are a consequence of two effects: (1) the solvent power of supercritical CO, to extract liquid-phase hydrocarbons at pressures below the saturation pressures of the overall mixtures and (2 the sensitivity of the L/V phase distribution to changes in pressure when the saturation pressure of the overall mixture is in the vicinity of its critical point. On a CO_2-free basis, retrograde liquid produced by flashing CO_2-enriched reservoir oil at 3,000 psia and 131deg.F [20.68 MPa and 328.15 K] was found to be similar in composition to other west Texas oils. Under conditions of repeated CO_2, contact, this retrograde liquid was found to revaporize like other west Texas oils.

(12645) A Laboratory Study of CO_2 Foam Properties and Displacement Mechanism

This paper presents the results of a comprehensive study of CO_2- foam physical properties and a series of displacement tests using a high pressure glass-lined flow-tube. The foam properties were studied in terms of foam quality, quantity and stability as functions of temperature, pressure surfactant concentration and surfactant mixing ratio. The CO -foam displacement tests were performed using SACROC and Rock Creek crude oils, and the oil recovery efficiency was visually investigated for both secondary and tertiary modes with varying CO_2 slug injection sequence and surfactant concentration.

The results indicate that the increase of pressure promotes foam stability whereas the increase pressure promotes foam stability whereas the increase of temperature does the contrary. It was found that CO_2- foam generated either externally or internally is susceptible to quick disintegration on contact with crude oil. Therefore, the control of CO_2 mobility using a foaming agent could be effective only within a short distance from the injection well. Any improvement on oil recovery or gas-oil ratio is probably obtained as a result of foam blockage of the permeable streaks or channels in the injection formation. It was found that excessively high concentrations of surfactant (foaming agent) may cause "foam barrier" to decrease sweep efficiency.

(11162) Ten Years of Handling CO_2 for SACROC Unit

SACROC Unit initiated CO_2 injection in 1972 for oil assisted recovery. Ten years of handling CO_2 through the compression, pipeline, injection, and removal facilities has confirmed their original designs and has caused some changes for improved operations. The reader should gain an awareness of the complexities involved in handling CO_2 and a perspective for better operating considerations in handling CO_2 in the oilfield.

(7091) Performance Review of a Large-Scale CO_2-WAG Enhanced Recovery Project, SACROC Unit Kelly-Snyder Field

This paper reviews the performance of the CO_2-WAG (water-alternating-gas) project conducted at the SACROC (Scurry Area Canyon Reef Operators Committee) Unit since early 1972. Numerous papers published previously describe in great detail the reservoir, previously describe in great detail the reservoir, the CO_2 displacement process, the transmission of CO_2 to the field, the mechanics of the operation of the project, a progress report through 1975, and other matters. Since detailed descriptions are available of reservoir characteristics, field history before the inception of the CO_2 project, planning and design, and facilities installations; these subjects will be reviewed only briefly here. The performance of CO_2 project itself since it began in J an. 1972 is emphasized. project itself since it began in J an. 1972 is emphasized. Kelly-Snyder Field, located in Scurry County, TX, is the major unitized field among four contiguous fields along the 35- x 5-mile (56.3- x 8.05-km) Canyon Reef formation (Fig. 1). Reservoir and fluid properties are summarized in Table 1. Estimated original oil in place in the SACROC Unit area, based on a volumetric determination, was 2.73 billion STB (434 Mm^3). This volume was used for the evaluation and design of the CO_2 miscible flood and for early estimates of incremental oil recovery resulting from CO_2 processing. In

1973, Chevron Oil Co., SACROC Unit operator conducted a 24-year history match of more than 1,500 wells in Kelly-Snyder Field using a two-dimensional black-oil simulator. On the basis of this study, the estimated original oil in place in the SACROC Unit area was reduced to 2.113 billion STB (335.9 Mm^3).

(7090) SACROC Tertiary CO_2 Pilot Project

Oil recovery by tertiary CO_2 flooding was pilot tested in a watered-out area in the SACROC pilot tested in a watered-out area in the SACROC Unit, Scurry County, Texas, during 1974-1975. Most of the SACROC Unit has been under a full scale enhanced recovery project using CO_2 since 1972 in areas not yet watered out. A 2.3 BSCF slug of CO_2 was injected into six wells in two adjacent, five-spot patterns in a watered-out portion of the reservoir over a period of nine portion of the reservoir over a period of nine months. Residual oil was displaced by the CO_2 approximately 64,000 STBO (3% of OOIP) was recovered.

This paper reports on the analysis of the field data including chemical tracer, pulse test, produced flood analyses and pressure measurements. produced flood analyses and pressure measurements. Performance was history matched with a Performance was history matched with a compositional simulator. The largest uncertainty in the project was in the CO_2 capture factor due to poor definition of the areal travel of the injected poor definition of the areal travel of the injected CO_2. The volumetric sweep efficiency of the CO_2 was calculated to be approximately 0.33. Fluid composition data showed that significant gas saturation was created by CO_2 injection and that interphase mass transfer enriched the produced fluids in intermediate hydrocarbons. The data and simulator results suggest that the flooding mechanism was not strictly miscible displacement. This study found evidence of CO_2 dissolving rock and aggravating the heterogeneities and tendencies Of CO_2 to channel. The data from the pilot produced a range of CO_2 requirements for a large produced a range of CO_2 requirements for a large scale project between 15 and 20 MSCF/STBO to give incremental recovery of 4% - 6% of OOIP for a 30% PV slug Of CO_2. This recovery efficiency was not PV slug Of CO_2. This recovery efficiency was not economic at $14.85 per barrel of oil.

(6391) Corrosion and Operational Problems, CO_2 Project, Sacroc Unit

The SACROC CO_2 Injection Project was initiated following a comprehensive literature search and extensive laboratory investigations to establish system design criteria, select suitable materials of construction, and prepare for operational difficulties that prepare for operational difficulties that might occur. Packing of the CO_2 Supply Line at the El Paso Puckett Plant was started in November 1971 and CO_2 injection commenced in three SACROC Unit wells on January 20, 1972. This is an alternating water-CO_2 project and all wells were placed on prewater injection prior to receiving the first slug of CO_2. System performance to date is considered satisfactory; however, some operational problems have occurred. One operating problem has problems have occurred. One operating problem has been corrosion. Corrosion has been minimal in the dry CO_2 portion of the injection system and maximum in meter runs, wellheads and tubing which are subject to alternating water-CO_2 slugs. The SACROC produced water is considered to be the greatest contributor to this area of maximum corrosion. Corrosion in the producing wells and surface equipment due to return of CO_2 has ranged from minimal to severe. Predictions of corrosivity based on CO_2 and water cuts have not always proved accurate. Although a few failures have occurred, equipment selection and inhibitor applications have adequately controlled corrosion in CO_2 Removal and Reinjection Facilities. Scale and emulsion problems have occurred in isolated instances problems have occurred in isolated instances but thus far have not posed a general problem due to proper treating and handling techniques.

(5536) Reservoir Description by Simulation at SACROC - A Case History

To determine areal distributions of pore volume and transmissibility in an effort to control a large CO_2-assisted recovery project, a 24-year history match of more than 1,500 wells was conducted with a two-dimensional, black-oil simulator. A good quantitative match resulted, which provided the necessary parameter distributions. Subsequent performance has largely supported the results of the study.

(5052) Compressibility Factors for CO_2-Methane Mixtures

Compressibility factors from a high-ratio CO_2-natural gas mixture are compared with other experimental data and values calculated using two correlations. Discussion includes the use of these factors in monitoring reservoir performance for the SACROC Unit CO_2 injection project.

(4804) Design and Operation of a Supercritical CO_2 Pipeline-Compression System SACROC Unit, Scurry County, Texas

The SACROC Unit is in the second year of a carbon dioxide miscible flood that is the largest secondary recovery project of this type ever undertaken. To accomplish this flood, over 35 million tons of carbon dioxide will be used for injection into the reservoir. The total cost of the project when finalized will be in excess of $175,000,000. This cost includes purchase of CO_2, conversion of over 200 producing wells to CO_2 injectors, expansion of surface facilities and the construction and operation of the CO_2 Pipeline-compression system. The magnitude and innovative nature of the project has demanded a major engineering, planning and design effort involving the coordination of many fields of engineering and various technical specialties. This paper will give a brief account of the overall CO_2 delivery facilities to include the basic design considerations and some of the studies that were conducted for each aspect of the project.

The focal point of the CO_2 transport project is the SACROC Unit in Scurry County, Texas. (Referring to Figure No. 1). It might be noted that the name SACROC was derived from the initials of the "Scurry Area Canyon Reef Operators Committee", a task group that was activated for essential work required prior to the formation of the SACROC Unit. The Canyon Reef field was discovered in 1948 with major development beginning in 1949 and extending through 1951. During this period, over 1,000 wells were drilled to develop more than 50,000 acres. The surface extent of the field is about 6 miles wide by 12 miles long.

Waterflood operations were started in 1954. By 1972, over 280 million barrels of oil had been produced by waterflood.

(4667) Effect of Supercritical Carbon Dioxide (CO_2) on Construction Materials

Laboratory tests showed that properly welded X-60 pipeline steel was not susceptible to environmental failure in supercritical carbon dioxide (CO_2); and corrosion rates were less than 0.02 mils penetration per year (MPY). Other tests showed penetration per year (MPY). Other tests showed nonmetallic seals to be susceptible to damage. Seals constructed from Teflon, nylon, semi-rigid polyurethanes and ethylene-propylene rubber were polyurethanes and ethylene-propylene rubber were acceptable. Thin-film coatings and centrifugally cast cement also were acceptable pipe linings.

(4083) Evaluation and Design of a CO_2 Miscible Flood Project-SACROC Unit, Kelly-Snyder Field

Investigations of alternative methods for improving recovery in the SACROC Unit showed that an inverted nine-spot miscible flood program consisting of injecting CO, driven by water would be the most effective and economical. Under such a scheme, the predicted ultimate recovery would be some 230 million barrels more than is expected from the original water injection program. program.

(1147) Reinjection of Large Volumes of Produced Water in Secondary Operations

A study was made of the operating performance histories of a pressure-maintenance and four waterflood projects in the Permian Basin area, where large volumes of produced water have been reinjected into the producing formations. The projects reviewed include a wide range of characteristics: (1) open and closed water systems, (2) volumes of reinjected water froth 2,200 to 12,500 B/D, (3) sand and limestone formations, (4) depths of 1.300 to 6,750 ft. (5) average permeabilities from 17 to 275 md, (6) bare and protected facilities, and (7) 10- to 50-year project life. Each project exhibited performance data which indicated that reinjection of large volumes of produced water provides a good source of injection fluid, results in practical and prudent salt water disposal and, in many cases, results in conservation of fresh water for future domestic needs.

(933) Desorption of Oxygen from Water Using Natural Gas for Countercurrent Stripping

Corrosion in the SACROC unit water flood was serious enough to warrant remedial action. A few months after installation of the flood, some injection wells were filled with 75 ft of iron hydroxides, and serious corrosion was occurring in the high-pressure pumps. The problem was studied and several methods of treating proposed, and the most promising was chosen. This method consisted of designing and constructing a tower for stripping oxygen from the injection water with countercurrent flow of natural gas.

TX-Salt Creek (Click Salt Creek to return to table)

(56882) Use of Full-Field Simulation to Design a Miscible CO_2 Flood

A study using full-field reservoir modeling optimized the design of a miscible CO_2 flood project for the Sharon Ridge Canyon Unit. The study began with extensive data gathering in the field and building a full-field three-dimensional geologic model. A full-field simulation model with relatively coarse gridding was subsequently built and used to history match the waterflood. This waterflood model highlighted areas in the field with current high oil saturations as priority targets for CO_2 flooding and generated a forecast of reserves from continued waterflooding. Predictions for the CO_2 flood used an in-house four-component simulator (stock tank oil, solution gas, water, CO_2. A full-field CO_2 model with more finely gridded patterns was built using oil saturations and pressures at the end of history in the waterflood model. The CO_2 model identified the best patterns for CO_2 flooding and was instrumental in selecting a strategy for sizing the initial flood area and in determining the size, location, and timing of future expansions of the CO_2 flood.

(39667) Permeability Predictions in Carbonate Reservoirs Using Optimal Non-parametric

In this paper, we have utilized a non-parametric transformation and regression technique called ACE (alternating conditional expectation) to estimate permeability from well logs at the Salt Creek Field Unit (SCFU), Texas, a heterogeneous reef carbonate reservoir. Previous attempts to derive permeability correlations at the SCFU have been less than satisfactory, leading to an over-dependence on porosity derived reservoir descriptions to predict fluid flow. Using non-parametric regression, we have now established a relationship between permeability and several common well logs that are available field-wide. These include density porosity, neutron porosity, shallow resistivity, deep resistivity and gamma ray logs. The approach adopted here also allowed US to integrate our geologic understanding of the reservoir into the non-parametric regression, further optimizing the final correlation. We have successfully predicted permeability in a majority of the uncored wells with acceptable accuracy at SCFU. These results have led to an enhanced reservoir characterization based on flow (permeability) rather than storage (porosity). This benefits both daily Operations and reservoir simulation efforts. This first, full-field application of ACE in a carbonate reservoir has demonstrated the strength and potential wide-scale use of non-parametric methods to predict permeability in heterogeneous reservoirs.

(23958) Case Histories of Step Rate Tests in Injection Wells

Knowledge of the formation parting pressure (FPP) is important for efficient operation and surveillance of waterflood projects and CO_2 floods. Knowing this information will assist in optimizing recovery by reducing injection rate. in wells to control cycling (i.e. prevent fluids from going through uncontrolled fractures or high permeability zones) or by increasing injection rates to maximize injection efficiency and increase oil production.

A step rate injectivity test (SRIT) is one of the best methods available to determine formation parting pressure, also known as the fracture parting pressure, also known as the fracture pressure. Previous step rate tests at Salt Creek pressure. Previous step rate tests at Salt Creek have been unsuccessful due to procedural problems resulting in inconclusive results.

This paper outlines the procedures, pitfalls, and field problems encountered while running successful step rate injectivity tests in the Salt Creek Field Unit. Findings obtained from running these tests include: frac gradient is highly dependent on average reservoir pressure; a correlation exists between average reservoir pressure and frac gradient for a particular field; bottom hole injection pressure measurements are extremely important on high rate injection wells; and theoretical formation parting pressure predictions are important in designing test procedures.

We also present results of conducting decreasing-rate-sequence SRIT. This is the first presentation of such data. The experience and presentation of such data. The experience and lessons learned from running these step rate tests can be successfully applied to other carbonate reservoirs.

TX-Seminole (Click Seminole to return to table)

(71496) Physical Effects of WAG Fluids on Carbonate Core Plugs

It is a given that carbonate mineral dissolution and deposition occur in a formation in geologic time and are expected to some degree in carbon dioxide (CO_2) floods. Water-alternating-gas (WAG) core flood experiments conducted on limestone and dolomite core plugs confirm that these processes can occur over relatively short time periods (hours to days) and in close proximity to each other.

(59691) San Andres and Grayburg Imbibition Reservoirs

Residual oil zones several hundred feet thick are found beneath many San Andres and Grayburg oil reservoirs in the Permian Basin, West Texas, suggesting that these reservoirs once contained a much larger oil volume. Oil has migrated out of these reservoirs, causing the oil-water contact and the zero capillary pressure level (zcpl) to rise, placing the reservoir in imbibition rather than drainage mode. Therefore, saturation profiles should be characterized by the imbibition capillary pressure curve. Imbibition curves have lower water saturations in the productive interval and significantly smaller transition zones than predicted by drainage curves. The reduction in the transition zone is a function of the rise of the zcpl, which is equal to the thickness of the residual oil zone. A more accurate estimate of original oil in place can be obtained if imbibition curves are used to model fluid saturations.

(36515) Integrated Reservoir Characterization Study of a Carbonate Ramp Reservoir: Seminole San Andres Unit, Gaines County, Texas

An integrated reservoir characterization of Seminole San Andres Unit was conducted using outcrop and subsurface data. The high-frequency cycles and rock-fabric facies identified on outcrop and cores were used to correlate wireline logs. Reservoir and simulation models of the outcrop and a two-section area of the Seminole San Andres field were constructed using rock-fabric units within high-frequency cycles (HFCs) as a geologic framework. Simulations were performed using these models to investigate critical factors affecting recovery.

High-frequency cycles and rock-fabric units are the two critical scales for modeling shallow-water carbonate ramp reservoirs. Descriptions of rock-fabric facies stacked within high-frequency cycles provide the most accurate framework for constructing geologic and reservoir models because discrete petrophysical functions can be fit to rock fabrics and fluid flow can be approximated by the kh ratios among rock-fabric flow units. Permeability is calculated using rock-fabric-specific transforms between interparticle porosity and permeability. Core analysis data showed that separate-vug porosity has a very strong effect on relative permeability and capillary pressure measurements.

The stratigraphic features of carbonates can be observed in stochastic realizations only when they are constrained by rock-fabric flow units. Simulation results from these realizations are similar in recovery but different in production and injection rates. Scale-up of permeability in the vertical direction was investigated in terms of the ratio of vertical permeability to horizontal permeability ($k_v k_h$). This ratio decreases exponentially with the vertical grid-block size up to the average cycle size of 20 ft (6.1 m) and remains at a value of 0.06 for a grid-block size of more than 20 ft (>6.1 m), which is the average thickness of high- frequency cycles. Simulation results showed that critical factors affecting recovery efficiency are stacking patterns of rock-fabric flow units, $k_v k_h$ ratio, and dense mudstone distribution.

(27715) Critical Scales, Upscaling, and Modeling of Shallow-Water Carbonate Reservoirs

High-frequency cycles and rock-fabric units are the two important scales for modeling shallow-water carbonate reservoirs. A reservoir model of the Seminole San Andres Unit (SSAU) was constructed that incorporated the high-frequency sedimentary cycles that compose the geologic framework and identified the rock fabric types of the principal flow units. Three rock-fabric units are used: dolograinstone, grain-dominated dolopackstone and medium crystalline mud-dominated dolostones, and fine crystalline mud-dominated dolostones. Rock properties such as capillary pressure and relative permeability are grouped according to rock fabric. Sensitivity studies and history matching in a two-section area of the SSAU suggest that rock-fabric-averaged models provide fluid saturation distribution more accurately than do cycle-averaged models.

The use of rock-fabric-dependent properties (initial water saturation, residual oil saturation, and relative permeability) in simulation predicts lower waterflood recovery. For carbonates with separate-vug porosity, waterflood recovery decreases and residual oil saturation increases with increasing vuggy porosity ratio (VPR). Residual oil saturation determined by the steady-state method is significantly lower than that determined by the unsteady-state method.

Upscaling permeability values into simulation block sizes was investigated using outcrop and core data. Using detailed minipermeameter data from outcrop it can be shown that the variogram range increases and the sill decreases with increasing horizontal block size. Effective vertical permeability of the simulation block is normally estimated using the ratio of harmonic mean to arithmetic mean of permeability. An analytical equation shows that this ratio is a function of variance rather than thickness.

History matching of primary production in a two-section area of the SSAU is dominated by vertical permeability, which controls the fractions of gas flowing vertically. In order to match production history, the vertical permeabilities used in the simulation are much lower than those measured from cores.

(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs

Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacings. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(24928) Update of Industry Experience with CO_2 Injection

The main purpose of this paper is to utilize current industry experience to evaluate the performance to date of miscible CO_2 injection projects. Also included is a summary of innovations being implemented by industry to improve recovery from existing CO_2 projects. Experience to date has shown that on balance, CO_2 injection projects have performed better than anticipated and offer a significant opportunity for improving ultimate recovery from existing reserves.

(24702) Defining Flow Units in Dolomitized Carbonate-Ramp Reservoirs

The problem of defining flow units in carbonate reservoirs has been investigated by integrated geological, petrophysical, and geostatistical outcrop studies. Results show that flow units (mappable intervals with similar petrophysical properties) can best be defined in terms of rock-fabric facies. Geostatistical analysis indicates that the different rock-fabric facies defined are significantly different but that within rock-fabric facies the petrophysical properties are near random. Detailed outcrop mapping shows that rock-fabric units are systematically arranged within genetic packages that have predictable stacking patterns within a sequence stratigraphic framework.

(19783) An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs

In this paper we present the results of a technical and an economic evaluation of waterflood infill drillings in fourteen Clearfork and eleven San Andres carbonate reservoirs in West Texas. The initial waterflood recovery efficiency and the infill drilling waterflood recovery efficiency were estimated from decline curve analyses. The economic analysis was performed to evaluate the relative profitability of the waterflood infill drilling operations.

For Clearfork units, the estimated initial waterflood recovery efficiency ranged from 9.54 to 32.19% of original oil in place (N) with a medium of 17.75%N; and the infill drilling waterflood recovery efficiency ranged from 13.09 to 52.56%N with a medium of 25.53%N. The medium increase in oil recovery by infill drilling was 7.78%N. For San Andres units, the initial waterflood recovery efficiency ranged from 10.68 to 39.03%N with a medium of 19.97%N; and the infill drilling waterflood recovery efficiency ranged from 13.73 to 44.58%N with a medium of 31.82%N. The medium increase in oil recovery by infill drilling was 11.38%N.

A multi-linear regression analysis was used to establish regression models correlating the initial waterflood and the infill drilling waterflood recovery efficiencies to reservoir and process parameters. For the Clearfork units, the process parameters. For the Clearfork units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 20.39%N and 3.19%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 29.25%N and 2.48%N, respectively. The average increase in oil recovery by infill drilling was 8.86%N. For the San Andres units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 22.09%N and 1. 45%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 32.23%N and 2.73%N, respectively. The average increase in oil recovery by infill drilling was 10.14%N.

Two cases were studied in the economic analyses. Case I economic analysis used past and projected production schedule and economic projected production schedule and economic parameters. For the Clearfork units, the rate of parameters. For the Clearfork units, the rate of return ranged from 18.37% to 125.2% with a mean of 53.3%. The payout ranged from 1.22 years to 6.58 years with a mean of 3.14 years. For the San Andres units, the rate of return ranged from 20.58% to 500.0% with a mean of 157.0%. The payout ranged from 0.36 to 5.43 years with a mean payout ranged from 0.36 to 5.43 years with a mean of 1.77 years.

Case II economic analysis used past and projected production data as though the projects projected production data as though the projects were initiated in January 1988. The base crude oil price of $17.50/STB was assumed in the analyses. For the Clearfork units, the rate of return ranged from 11.41% to 98.80% with a mean of 40.4%. The payout ranged from 1.45 to 6.42 years with a mean of 3.53 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 4.28 years and 3.13 years using $22.50/STB. For the San Andres units, the rate of return ranged from 20.58% to 500.00% with a mean of 157.00%. The payout ranged from 2.36 to 4.91 years with a mean of 2.3 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 2.18 years and 2.00 years using $22.50/STB.

(17290) New Fiberglass Liner Completion Technique Salvages Old Injection Wells for Use as WAG Injection Wells

Fiberglass liners with polished bore seal assemblies are being successfully used to salvage old injection wells as less than half the cost of drilling the wells again. Components of conventional waterflood fiberglass liner completion equipment used in the past to improve well conditions and injection profile control were modified or changed.

(16854) Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas

This paper presents the results of an economic analysis of infill drilling in 16 carbonate oil reservoirs located in West Texas. The economic analysis included the evaluation of incremental waterflooding recovery over primary and infill drilling recovery over initial waterflooding.

Because of limited field and economic data available for this study, many assumptions were made to complete the economic evaluations. Two major cases of economic evaluation were performed: Case 1 used the past production and economic data to 1986 and the projection of these data from 1986 on to the assumed economic limit, and Case II used the past infill production data as if the projects were initiated in January 1986 and on to the assumed economic limit.

Results showed that about 6811 of the infill drilling projects studied had an infill drilling incremental payout of less than two years with a incremental discounted cash flow rate of greater than 20%. Only 37% of the projects studied had a waterflood incremental economics with the same criteria. Decreasing the well spacing generally decreased the infill drilling incremental payout and increased the incremental cash flow rate of return. As the OOIP/WS (well spacing) increased, the general trend showed an increasing infill drilling incremental net present value.

Results from Case II studies showed that for a \$15/STB (\$94/m 3) oil price in 1986, about 68% of the infill drilling projects studied had an infill drilling incremental payout of less than two years with an incremental discounted cash flow rate of return greater than 20%. As the OOIP/WS increased, the general trend also showed an increasing infill drilling incremental net present value. When the oil price in 1986 was increased from \$15/STB (\$94/m 3) to) \$25/STB 0157/m 3), the increase " the incremental net present value (INPV) was substantial. For example at a value of 20 for OOIP/WS (Means Field/San Andres), the INPV increased from \$76 MM to \$122 MM.

(10022) The Role of Numerical Simulation in Reservoir Management of a West Texas Carbonate Reservoir

An effective reservoir management program is designed to optimize reservoir performance by assuring maximum economic return and recovery over the life of the reservoir. Such a program requires a continuing process of engineering and geologic study. Numerical reservoir simulation models provide a powerful tool for analyzing the production history of a reservoir and for production history of a reservoir and for predicting future performance under a variety of predicting future performance under a variety of possible operating methods. Experience has possible operating methods. Experience has shown that can accurate reservoir description is essential to the success of any numerical simulation study and to the development of an effective reservoir management plan.

The mechanics of conducting a numerical simulation of reservoir performance are essentially the same for either a carbonate or sandstone reservoir. The most important difference in modeling these two general reservoir types involves the conceptual approach required to describe the lateral and vertical continuity of flow units within the reservoir. The continuity and internal characteristics of sandstones are controlled primarily by the original depositional system and environment, with usually only minor post-depositional changes. In carbonates, the post-depositional changes. In carbonates, the distribution of porosity and permeability and the continuity of reservoir-quality units can be determined either by the original depositional environment, by post-depositional diagenetic changes, or, most commonly, by a combination of these factors.

Carbonate reservoir rock types are formed in a variety of depositional settings and show great diversity in size and form, ranging from reefs covering one or two square kilometers to extensive carbonate banks covering thousands of square kilometers. The common characteristic of carbonate reservoirs is the extreme heterogeneity of porosity types and permeability distribution which results from the complex interaction of the physical, biological, and chemical processes that form these rocks. In addition, carbonate rocks are particularly susceptible to post-depositional diagenetic changes. Some of post-depositional diagenetic changes. Some of the more important diagenetic processes which act to after the original rock texture in carbonates are dolomitization, recrystallization, cementation, and leaching or solution.

A reservoir study conducted by Cities Service Company on a large carbonate reservoir in West Texas provides an excellent example of the approach and the type of data needed to support a numerical simulation study for improved reservoir management. The West Seminole field produces from the San Andres Formation at an average depth of approximately 5,100 ft (1550 m). The general structural configuration of the reservoir consists of a large main dome with a smaller dome structure to the east. A large primary gas cap covers most of the field area. The field was discovered in 1948. During the late 1960's and early 1970's, efforts were made to reduce the pressure decline in the reservoir by re-injection of produced gas into the gas cap and by peripheral water injection. Neither of these was entirely successful in effecting pressure maintenance. In the mid-1970's, the decision was made to develop a 40-acre (16.2-ha) five-spot pattern waterflood in the main dome area of the field. Twenty-eight infill water injection wells were drilled during 1973-1975.

Throughout the field's producing life, there had been a question about the extent of vertical communication within the reservoir, particularly between the oil zone and the particularly between the oil zone and the overlying gas cap.

(8274) Improved Reservoir Characterization: A Key to Future Reservoir Management for the West Seminole San Andres Unit

A comprehensive reservoir study using a black-oil simulation model showed that control of vertical movement of oil into the gas cap under waterflood operations was the key to maximizing oil recovery from this west Texas San Andres reservoir. Recovery of an additional 4 MMSTB of oil is expected as a result of a reservoir management plan which includes a 46-well infill drilling program.

(7796) Sheep Mountain CO_2 Production Facilities - A Conceptual Design

This paper discusses the potential supply of CO_2 for enhanced recovery projects from the natural CO_2 reservoir at Sheep Mountain, Huerfano projects from the natural CO_2 reservoir at Sheep Mountain, Huerfano County, CO. Producing well characteristics are examined, and a conceptual process is discussed for separation of water, dehydration, compression, and transportation of 300 MMscf/D of CO_2 from Colorado to Texas. (Line would terminate at the Seminole Unit)

(6738) Reservoir Data Pays Off: West Seminole San Andres Unit, Gaines County, Texas

At this point in time the oil industry is under considerable pressure to maximize recoveries from existing reservoirs. In order to obtain this goal it is necessary that a reservoir be accurately described as to its internal structure and producing mechanisms. Improper definition of a reservoir producing mechanisms. improper definition of a reservoir can result in a very inefficient operation and thus a lower recoverable reserve value. This paper is being presented as an example of how the interpretation of internal structure and producing characteristics of a particular reservoir has changed as a result of an extensive reservoir data gathering program. The new information has drastically program. The new information has drastically changed the concept as to how this reservoir should be managed.

(4064) Efficient Removal of Oxygen in a Waterflood by Vacuum Deaeration

A one-stage vacuum deaeration process with supplemental gas stripping is being used to reduce the oxygen content of about 40,000 barrels per day of source water to 0.05 ppm or less for per day of source water to 0.05 ppm or less for use in the Robertson Waterflood near Seminole, Texas. The vacuum deaeration process is based on the reduced solubility of oxygen in water at reduced pressure and oxygen content of equilibrium vapors. Addition of an inert gas to the contact tower of a vacuum deaeration process further reduces the concentration of oxygen in equilibrium vapors and thereby the dissolved oxygen in the treated waters. The Robertson plant is mechanically simple and fully automated. plant is mechanically simple and fully automated. The water flows through a packed tower to a treated water surge tank. Water from the surge tank is pumped to waterflood injection wells. A vacuum down to 1.0 inch of mercury absolute is supplied to the contactor by a water sealed pump. The contactor is elevated to provide pump. The contactor is elevated to provide gravity flow into the surge tank. Flow rates are controlled relative to the level in the surge tank to equal the demand of downstream injection pumps.

In operation, the one-stage vacuum deaeration alone reduces the oxygen content of the water to approximately 0.17 ppm. Addition of 0.1 cubic foot of natural gas per barrel of water further reduces the oxygen content to 0.05 ppm or less. The inlet water contains 20 ppm carbon dioxide and some calcium at a pH of 7.4. In this case, partial removal of the carbon dioxide with increase in pH to 7.7 has not caused any carbonate scaling. The corrosivity of the inlet water is being reduced from 14 mils per year (mpy) to 1.6 mpy. The plant has operated essentially maintenance free at a treating cost of 0.17 mils per barrel.

TX-Sharon Ridge (Click Sharon Ridge to return to table)

(65029) Mineral Scale Control in a CO_2 Flooded Oilfield

This paper presents a case study of improving scale inhibition treatments in the Sharon Ridge Canyon Unit (SRCU), West Texas in response to the increased scaling conditions that has arisen from carbon dioxide (CO_2) injection into the oil reservoir.

In anticipation of increased scale deposition, a proactive approach was taken by carrying out a comprehensive field system analysis and scale survey prior to the commencement of CO_2 flooding at SRCU. This analysis/survey was intended to assess the new situation and come up with a cost effective scale treatment program. A laboratory evaluation of a number of scale inhibitors was then carried out. Based on our understanding of the problem and the lab evaluation results, a new scale inhibitor and a new chemical treatment program were developed and implemented in the field.

This paper describes the system analysis/scale survey and highlights its importance in understanding the changing situation and the new challenges in scale inhibition arising from CO_2 flood. The laboratory evaluation for identifying the most suitable and cost-effective inhibitor is then briefly described. The paper then discusses the new scale inhibition treatment program and scale monitoring program. The field results from implementing the new treatment program are presented and discussed. Owing to the proactive approach and the improved inhibitor and treatment, the field production system and water re-injection system have not been troubled with scale deposition.

(56882) Use of Full-Field Simulation to Design a Miscible CO_2 Flood

A study using full-field reservoir modeling optimized the design of a miscible CO_2 flood project for the Sharon Ridge Canyon Unit. The study began with extensive data gathering in the field and building a full-field three-dimensional geologic model. A full-field simulation model with relatively coarse gridding was subsequently built and used to history match the waterflood. This waterflood model highlighted areas in the field with current high oil saturations as priority targets for CO_2 flooding and generated a forecast of reserves from continued waterflooding. Predictions for the CO_2 flood used an in-house four-component simulator (stock tank oil, solution gas, water, CO_2. A full-field CO_2 model with more finely gridded patterns was built using oil saturations and pressures at the end of history in the waterflood model. The CO_2 model identified the best patterns for CO_2 flooding and was instrumental in selecting a strategy for sizing the initial flood area and in determining the size, location, and timing of future expansions of the CO_2 flood.

(39629) Use of Full-Field Simulation to Design a Miscible CO_2 Flood

A study using full-field reservoir modeling optimized the design of a miscible CO_2 flood project for the Sharon Ridge Canyon Unit. The study began with extensive data gathering in the field and building a full-field 3D geologic model. A full-field simulation model with relatively coarse gridding was subsequently built and used to history match the waterflood. This waterflood model highlighted areas in the field with current high oil saturations as priority targets for CO_2 flooding and generated a forecast of reserves from continued waterflooding. Predictions for the CO_2 flood used an in-house 4-component simulator (stock tank: oil, solution gas, water, CO_2). A full-field CO_2 model with more finely gridded patterns was built using oil saturations and pressures at the end of history in the waterflood model. The CO_2 model identified the best patterns for CO_2 flooding and was instrumental in selecting a strategy for sizing the initial flood area and in determining the size, location, and timing of future expansions of the CO_2 flood.

(3443) Performance of Sharon Ridge Canyon Unit with Water Injection

Although this waterflood had performed beautifully for fifteen years, a detailed geologic and engineering study revealed that if all areas of the unit were to be depleted efficiently the peripheral injection pattern would have to be modified. The moral: keep a gimlet eye on that flood; its beauty may be only skin deep.

(37) Pressure Maintenance Operations in the Sharon Ridge Canyon Unit, Scurry County, Tex.

The Sharon Ridge Canyon Unit is a pressure maintenance project using fresh surface water injected on a peripheral pattern. Canyon Reef limestone of Pennsylvanian age, occurring at approximately 6,700 ft, comprises the producing reservoir. The original producing mechanism was that of an undersaturated solution-gas drive. Rapid pressure decline and the threat of climbing gas-oil ratios pointed toward the need for pressure maintenance. Performance to date under the influence of water injection has been very encouraging. During six years of water injection, the volumetric average reservoir pressure has increased

338 psi, from 1,583 to 1,921 psi. The producing gas-oil ratio has been reduced from about 1,300 to about 900 cu ft/bbl. Before water injection, it was necessary to withdraw approximately 2.3 reservoir bbl in order to place 1 bbl of oil in the stock tank. Now, 1 bbl of stock-tank oil requires a withdrawal of only 1.8 reservoir bbl. Peripheral portions of the reservoir which have experienced encroachment by the injected water have performed better than predicted. Based on this history and recovery predictions, ultimate recovery as a result of this water injection will be at least 50 per cent of the original oil in place. This is twice the predicted recovery without pressure maintenance.

TX-Slaughter (Central Mallet) (Click Slaughter (Central Mallet) to return to table)

Central Mallet articles are all included in other Slaughter unit articles, see the following sections

TX-Slaughter Estate (Click Slaughter Estate to return to table)

(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs

Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacings. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

(26624) Reservoir Management in Tertiary CO_2 Floods

Since 1984, Amoco has operated four major enhanced oil recovery projects using CO_2 in West Texas. Due to the high cost of CO_2 injectant, the economic success of these floods depends on the ability to properly monitor and manage CO_2 utilization. This paper describes a new approach to the surveillance and management of the Slaughter Estate Unit CO_2 flood. The method described here involves real-time monitoring on a well-by-well, pattern-by-pattern basis by displaying raw as well as processed data using the "Montage" concept. Using this concept, injection, production, and other data from a well or a group of wells can be viewed simultaneously by zooming into any area of the field. Inter-well communication and gas cycling can be recognized quickly and changes in operating variables can be made. As a result, the economic performance of a CO_2 flood can be optimized by making prompt adjustments to gas-water ratio, CO_2 and water half-cycle slug sizes, and injection and production well pressures.

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(23974) Analysis of Tertiary Injectivity of Carbon Dioxide

The most important conclusion is that the mixing phenomenon due to dispersion, crossflow and viscous instability that models neglect can significantly influence injectivity. The results indicate that three-phase flow of gas, oil and brine needs to be modeled and that, contrary to the conclusions of other investigators, three-phase flow effects can have important influences on injectivity, even when CO_2 is injected above its MMP. In addition, the most sensitive relative permeability parameters for reservoir-scale, tertiary CO_2 flooding conditions in parameters for reservoir-scale, tertiary CO_2 flooding conditions in the presence of correlated permeability heterogeneity are identified. Sensitivity to the relative permeability parameters can also be substantial, even at low permeability contrast. The results presented in this paper are particularly pertinent to the hybrid-WAG displacement process since they provide information about the first cycle of CO_2 injection.

(19375) Slaughter Estate Unit CO_2 Flood: Comparison Between Pilot and Field-Scale Performance
This paper describes the performance of a pilot and a unitwide CO_2 flood in the Slaughter Estate Unit, Slaughter field, Hockley County, TX. The performance and design of both projects are compared to yield insight into the process, the impact of flood design variables, and the effects of project scale.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987
Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(16830) CO_2 Injection and Production Field Facilities Design Evaluation and Considerations
Many technical papers have been published on CO_2 flooding from a reservoir standpoint; but, few have ever discussed design considerations of field CO_2 production and injection facilities. This paper will present initial design and installation considerations, design criteria, and initial installation problems associated with Amoco's four West Texas CO_2 projects (Slaughter Estate Unit, Central Mallet Unit, Frazier Unit, Wasson ODC Unit). Additionally, design and operational considerations, based on the experience gained from operating the four CO_2 floods during the last two years, will be discussed for use in future CO_2 facility designs.

Equipment problems which have been experienced during operation, modifications which have been made as a result of experience, and recommended changes for future designs will be discussed in this paper. Actual case histories of operations, equipment design, and equipment problems encountered will be presented. The specific areas to be discussed will include: The CO_2 injection system material selection and layout, CO_2 injection wellhead material selection and configuration, CO_2 injection well downhole equipment, producing wellhead pressure and material requirements, flowline and fluid gathering systems, satellite and central tank battery layout and operation, and the gas collection system layout and material selections.

Special considerations will be given to design details and material specifications that are often overlooked, or not considered. The resulting potential problems and failures of these oversights will be discussed.

(16716) The Effects of CO_2 Flooding on Wettability of West Texas Dolomitic Formations
Reduced water injectivity after CO_2 injection has frequently occurred in West Texas oil fields. One explanation proposed for this phenomenon was a change in rock wettability by the CO_2 and crude oil miscible bank. This paper describes an experimental study to determine the effects Of CO_2 flooding on the wettability of West Texas dolomitic cores.

This study examined the relative permeability characteristics of fresh-state San Andres and Grayburg dolomite core samples before and after passing a crude Oil/CO_2 miscible front through the test core. Changes in the relative permeability characteristics were used to infer the effects Of CO_2 flooding on rock wettability. The cores chosen were intermediate oil wet, intermediate, and intermediate water wet. The results showed that the cores became slightly more water wet. However, this change in wettability was near the limit of statistical confidence. Some data suggests that the tendency to becoming water wet was cause by slight rock dissolution by the CO_2 and brine. Some observations concerning the compatibility of brines used in laboratory core floods with dolomites containing anhydrite are discussed.

(10727) Slaughter Estate Unit Tertiary Miscible Gas Pilot Reservoir Description
A reservoir description for the Slaughter Estate Unit tertiary pilot and surrounding area and the procedure that we used to obtain it are discussed in this paper. The procedure is based on matching waterflood performance procedure is based on matching waterflood performance prior to pilot miscible gas injection with a black oil prior to pilot miscible gas injection with a black oil reservoir simulator. An initial estimate of the reservoir description is obtained from petrophysical data and single-well pressure transient tests. The initial estimate is then modified by a trial and error procedure until a good match between the actual and calculated waterflood performance is obtained. Performance is obtained. It was determined that the Slaughter Estate Unit tertiary pilot had an original oil in place (OOIP) of 642,400 STB [102 133 stock-tank m3]. A waterflood prediction derived from the reservoir description in this paper indicates that a primary-plus-secondary recovery through Sept, 30, 1983, of 49.6% OOIP would have been obtained from the pilot if waterflood operations had been continued. On the basis of this prediction, it was established that the tertiary oil recovery resulting from the miscible gas process was 18.5% OOIP as of Sept. 30, 1983.

(9796) Slaughter Estate Unit Tertiary Pilot Performance
Amoco Production Co. began in the early 1970's to work toward a reservoir test of the CO_2 miscible displacement process in the Slaughter Estate Unit (SEU). Because of difficulties in obtaining a reliable pure CO_2 source, a feed gas stream to the Slaughter gasoline plant sulfur recovery unit was chosen as the solvent injection source. This solvent gas stream consisted of approximately 72% CO_2 and 28% hydrogen sulfide. Laboratory tests demonstrated that the displacement process using this acid gas as a solvent was the same as process using this acid gas as a solvent was the same as when pure CO_2 was used.

Six pilot injection wells and two pilot producers were drilled in 1972 in a portion of the SEU (Slaughter field) that had not been waterflooded. Waterflooding was begun in 1972 and a peak secondary oil rate of 407 BOPD (64.7 m^3/d oil) was observed in June 1973. By mid-1976 most of the secondary oil had been produced, a secondary decline rate was well established, and the WOR had increased significantly.

Alternate solvent Gas and water injection, for favorable areal sweep, was initiated in Aug. 1976, and the first tertiary oil production was observed in Oct. 1977 when oil production from the two pilot producers increased from 22 to 29 BOPD (3.5 to 4.6 m^3/d oil). Peak tertiary production was 152 BOPD (24.2 m^3/d oil) Peak tertiary production was 152 BOPD (24.2 m^3/d oil) in Feb. 1979. Through July 1981 the pilot was still producing about 70 BOPD (11.1 m^3/d oil) and cumulative producing about 70 BOPD (11.1 m^3/d oil) and cumulative incremental tertiary oil production was 95,680 STB (15 212 stock-tank m^3), which represents 14.9% original oil in place (OOIP).

A total of 26% hydrocarbon pore volume (HCPV) Solvent gas was injected into the pilot area through Oct. 1979. In Nov. 1979 nitrogen chase gas injection was initiated; an interruption in the pilot's nitrogen supply in April 1980 forced a temporary change to residue chase gas injection until Dec. 1980 when nitrogen injection was resumed. Current plans call for the injection of 29.6% HCPV chase gas into the pilot area.

The SEU tertiary pilot was conducted so that both secondary and tertiary recovery factors could be delineated clearly by actually measuring oil in the tank. Performance data from this pilot conclusively show that Performance data from this pilot conclusively show that alternate CO_2 -water will move tertiary oil in significant quantities in this and similar west Texas reservoirs.

(8830) Slaughter Estate Unit CO_2 Pilot - Surface and Downhole Equipment Construction and Operation in the Presence of H_2S

This paper presents the material selection, construction procedures, safety devices, corrosion control and monitoring, and operational procedures necessary for successful compression, transportation, and injection of a gas stream containing 28% hydrogen sulfide. It also discusses various operational problems encountered during the 3-year project life. project life.

TX-Slaughter Field (Click Slaughter Field to return to table)

(71496) Physical Effects of WAG Fluids on Carbonate Core Plugs

It is a given that carbonate mineral dissolution and deposition occur in a formation in geologic time and are expected to some degree in carbon dioxide (CO_2) floods. Water-alternating-gas (WAG) core flood experiments conducted on limestone and dolomite core plugs confirm that these processes can occur over relatively short time periods (hours to days) and in close proximity to each other.

(70068) Conformance Water-Management Team Developments and Solutions on Projects in the Permian Basin

A team was formed to solve field-wide conformance problems in a San Andres (dolomite) unit of the Slaughter Field, Hockley Co., Texas. The team's goal was to increase oil production and decrease production costs by understanding fluid movement through the reservoir. The team was comprised of operating and service company personnel who performed data analysis, and developed engineering and solution designs.

The reservoir conformance team identified, quantified, and fully described field conformance problems. Team members focused on understanding fluid movement through the total reservoir rather than on single wells. They developed a framework of data for designing successful conformance solutions. This framework includes data about the reservoir, completion design, drilling and workover history, production and well-test history, logs, diagnostic analysis, and placement options. The framework serves as a data-collection tool and as a tool for identifying missing data.1

This project involves the following tasks: (1) analyzing approximately 300 wells, (2) identifying conformance candidate (pilot) wells, (3) implementing the pilot wells, (4) analyzing the results from the pilot wells, and (5) applying those results to the rest of the unit.

In this project, team members developed the typical data analysis, reservoir and production engineering proposals, and solutions proposals, and also thoroughly reviewed the customer's economic drivers. In these mature units, enhancing recovery and production rates and reducing costs were important factors.

Treatments have been placed and analyzed for sweep improvement, CO_2 reduction, and water cycling-breakthroughs.

(27648) Normalization of Cased-Hole Neutron Logs, Slaughter Field, Cochran and Hockley Counties, Texas

Currently accepted methods of normalizing cased hole neutron logs to porosity were determined to be unusable under conditions encountered during a reservoir study of the Texaco Bob Slaughter Block and nearby leases in Slaughter field, Cochran and Hockley counties, Texas. A new method for normalizing a large number of neutron logs was developed which is applicable in a wide range of situations.

The method employs statistical parameters derived from available core and modern log suites to dependably transform the neutron log response. Unlike earlier techniques, a linear transform equation is developed for each log being normalized. The method calculates the slope of the transform equation comparing the standard deviation of the neutron values to a reference log with similar characteristics over a specified depth interval. The intercept of the transform line is then calculated from average porosity values for a specific interval not necessarily the same interval used to calculate the standard deviation. The technique eliminates inaccuracies in the normalization process created by tool differences, scale factors, and hole size. The effect of changes in lithology and formation fluid on the resulting porosity values are also minimized.

(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs

Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacings. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

(26335) Coiled-Tubing Sidetrack: Slaughter Field Case History

The paper describes the successful sidetrack of an oil well in the Slaughter Field in West Texas using coiled tubing (CT). Several first-time CT operations performed during this workover include:
Setting a whipstock in casing on CT Cutting a window with CT Using measurement-while-drilling (MWD) with CT in a "real" well Use of a fluid-operated orientation tool for in-hole toolface changes Successful use of an "autodriller" to maintain weight on bit while drilling Directional control of the sidetracked hole proved to be ineffective due to a surface software problem. The resultant wellbore was not horizontal as planned, but instead closely paralleled the original well for much of its length. However, the previously non-productive well flowed 1000 barrels of fluid per day (BFPD) from the sidetrack following the workover.

(24928) Update of Industry Experience With CO_2 Injection

The main purpose of this paper is to utilize current industry experience to evaluate the performance to date of miscible CO_2 injection projects. Also included is a summary of innovations being implemented by industry to improve recovery from existing CO_2 projects. Experience to date has shown that on balance, CO_2 injection projects have performed better than anticipated and offer a significant opportunity for improving ultimate recovery from existing reserves.

(20377) Optimization of Waterflood Performance and CO_2-Flood Design Using a Modeling Approach, Mallet Unit, Slaughter Field

The Mallet Unit, located in Cochran and Hockley Counties of west Texas, produces oil from the Permian San Andres dolomite as part of the larger Permian San Andres dolomite as part of the larger Slaughter field. The Mallet Unit was evaluated for waterflood improvement and $C0_2$ enhanced oil recovery. This paper discusses the modeling approach for optimizing the existing waterflood and designing a CO_2-flood. Four Components were found instrumental in achieving a reliable CO_2-flood design. These four components are: (1) an Equation-of-state accurately matched with representative PVT data, (2) a reliable geological description validated by 23 years of waterflood history, (3) a compositional model which adequately describes the phase behavior and CO_2 displacement mechanism, and (4) a valid scale-up technique for forecasting field-scale CO_2-flood performance from pattern CO_2-flood performance. With these four pattern CO_2-flood performance. With these four Components, oil and $C0_2$ production response forecasted from the compositional model and scale-up study were found to be in reasonable agreement with the field observation of a near by CO_2-flood. This nearby CO_2-flood has similar geology and fluids. Recommendations for waterflood improvement and CO_2-flood design were made based on both black-oil and compositional simulation results.

(20115) Reactivity of San Andres Dolomite

The San Andres formation is routinely stimulated with acid. Although numerous acidizing simulators are available to aid in treatment optimization, existing reactivity data were generated with quarried rock rather than formation samples. This paper presents reactivity data for five San Andres dolomite samples. These data can be used in most fracture-acidizing-design simulators to allow more accurate simulation of the acidizing process.

(19375) Slaughter Estate Unit CO_2 Flood: Comparison Between Pilot and Field-Scale Performance

This paper describes the performance of a pilot and a unitwide CO_2 flood in the Slaughter Estate Unit, Slaughter field, Hockley County, TX. The performance and design of both projects are compared to yield insight into the process, the impact of flood design variables, and the effects of project scale.

(16831) Carbonated Waterflood Implementation and Its Impact on Material Performance in a Pilot Project

Carbonated waterflooding is an enhanced oil recovery process developed in the early 1950's that may have potential application in several West Texas reservoirs. The process consists of saturating injection water with CO_2 in order to swell the remaining oil-in-place, and thereby increase the amount of recoverable oil in a reservoir. The process usually involves less investment and CO_2 demand than miscible CO_2 flooding.

The effects of carbonated waterflooding on equipment material performance were monitored during a two well carbonated water injection pilot test conducted by Amoco Production Company in the Slaughter Field, Hockley County, Texas. Stainless steel and aluminum bronze material showed no deterioration during the test period. However, severe problems were encountered at holidays in the internal plastic coating of carbon steel pipe and fittings. Injection well material performance data and observations are presented to support these findings. In addition, the surface equipment design used to saturate injection water with CO_2 will be presented. No attempt will be made to discuss the impact of carbonated waterflooding on injection well or reservoir performance.

(14308) Investigation of Unexpectedly Low Field-Observed Fluid Mobilities During Some CO_2 Tertiary Floods

Phase behavior, inorganic precipitation, and wettability are investigated as possible reasons for the unexpectedly low field-observed mobilities during some CO_2 floods, in particular, the Denver Unit, Wasson field CO_2 pilot. The observed mobility was not a near-wellbore effect and probably played a major role in reservoir sweep: the low effective probably played a major role in reservoir sweep: the low effective permeability offset the detrimentally low CO_2 viscosity. Experimental and permeability offset the detrimentally low CO_2 viscosity. Experimental and simulation studies, supplemented by literature data, lead to the conclusion that rock wettability could be the root cause of these low fluid mobilities. Phase behavior effects, though they may play a role, are not necessary to explain the injectivity behavior, and inorganic precipitates probably have little effect under the conditions investigated here. Thus, probably have little effect under the conditions investigated here. Thus, current simulator modeling of low fluid mobilities, which are based on arbitrary permeability reduction factors allegedly caused by phase behavior, appears unjustifiable even though overall simulator results may be acceptable.

(14288) A CO_2 Injection Measurement and Control System

Advances in microcomputer technology have heralded a new era in oil field automation. A novel measurement and control system has been implemented on the carbon dioxide injection wells in the Slaughter and Wasson Fields operated by Amoco Production Company. The heart of this system is a solar powered microprocessor based Remote Telemetry Unit which senses the necessary input parameters, performs the calculations necessary to measure the rate and pressure at which carbon dioxide is being injected, pressure at which carbon dioxide is being injected, controls the position of a ball valve to maintain the desired flow rate and pressure, and sends selected information to a central automation computer for alarm and reporting purposes. The purpose of this paper is to describe the electronic purpose of this paper is to describe the electronic hardware, the end devices, control element, and software that was used to implement this function.

(12015) Comprehensive Geological and Reservoir Engineering Evaluation of the Lower San Andres Dolomite Reservoir, Mallet Lease, Slaughter Field, Hockley County, Texas

The Mallet Lease, Hockley County, western Texas, produces oil from the Permian San Andres Dolomite as produces oil from the Permian San Andres Dolomite as part of the larger Slaughter Field. The Mallet Lease part of the larger Slaughter Field. The Mallet Lease is being considered for infill drilling and for tertiary recovery. This paper discusses the engineering and geologic basis of the reservoir description that is used in history matching 40 years of primary and secondary performance. Emphasis is given to integration of reservoir description with necessary fluid flow properties needed to match performance and also the use of long term data to insure proper reservoir representation.

There are no discontinuous, isolated portions of the reservoir that would be tapped by infill wells. Most of the remaining oil is located in the tighter portions of the producing intervals which bears on portions of the producing intervals which bears on prospects for infill drilling and tertiary oil recovery. prospects for infill drilling and tertiary oil recovery.

(7570) Use of Fine Salt as a Fluid Loss Material in Acid Fracturing Stimulation Treatments
This paper discusses a new secondary fracture fluid-loss material that is being employed successfully in treatments of the San Andres formation (Slaughter Field, TX). The use of fine mesh salt in this reservoir containing less than saturated brine is presented as a substitute for fine mesh sand, providing equal or better production increases as providing equal or better production increases as obtained with fine mesh sand, without production equipment problems commonly associated with post-treatment fine mesh sand returns. Production results post-treatment fine mesh sand returns. Production results of fine mesh salt stimulation techniques are shown and compared with presently popular stimulation technique results.

(4070) A Modeling Approach for Optimizing Waterflood Performance, Slaughter Field Chickenwire Pattern
A two-dimensional areal simulation indicated significant trapping of oil between center and off-center producers in this unique waterflooding pattern. For typical conditions, the predicted ultimate recovery of 41 pattern. For typical conditions, the predicted ultimate recovery of 41 percent of original oil in place was increased to 44.6 percent by drilling percent of original oil in place was increased to 44.6 percent by drilling additional producers between center and off-center producing wells.

(1576) Computer Processing of Log Data Improves Production in Chaveroo Field
Computer log analysis has proved quite successful in the Chaveroo field of Roosevelt County, N.M., in a carbonate section of low permeabilities, low porosities and variable water saturations. Production in this field occurs at about 4,300 ft in the San Andres formation, a Permian carbonate with a mixture of dolomite, anhydrite and gypsum, and lesser amounts of silica, limestone and silt. Sonic, density and neutron logs, all of which respond differently to porosity and lithology, enable a mathematical solution that defines the fractions of major lithologic components and gives the correct porosity. The Laterolog and Microlaterolog are used to solve for a movable oil relationship. The computer output is a log of bulk volume percentages of porosity, dolomite, anhydrite, gypsum and silica, and a movable oil plot. The record shows that wells completed on the basis of this computer log analysis statistically have higher initial productions and lower water cuts than wells completed on the basis of less diagnostic logging techniques.

(341) Small Propane Slug Proving Success in Slaughter Field Lease
A propane-gas-water miscible-phase displacement process has been in operation on the H. T. Boyd lease, Slaughter field, since May, 1958. The total requirement of 255,416 bbl of liquid propane and 2,625 MMcf of residue gas has been injected. These materials were injected to obtain the high unit displacement efficiency of a miscible process in a portion of the reservoir. This lease is not bounded and the pressure differential created by high injection rates places a limit on the area to be miscibly swept. Water injection is being used to improve the miscible sweep, to displace the oil bank, and to flood portions of the reservoir not miscibly contacted. A total of 4.2-million bbl of water has been injected. The lease performance history indicates the small propane slugs have created a substantial oil bank in the major portion of the reservoir. Considerable test data have been obtained and interpreted to determine the type of displacement in each injection area. These data show that a portion of each injection area has been miscibly swept. There is a wide variation in performance between the areas, and this difference is attributed to permeability stratification. Field data have been used to make required changes in the original plan of operation, and miscible displacement is continuing. The small propane slugs (about 3 per cent of the volume to be miscibly contacted) are expected to sweep at least 18 per cent of the hydrocarbon pore volume. The predicted recovery for this project is 58 per cent of the oil in place. This recovery is about 1.5-million bbl of oil over the predicted waterflood recovery, and it is almost three times the predicted primary recovery.

TX-Slaughter Frazier (Click Slaughter Frazier to return to table)
(16830) CO_2 Injection and Production Field Facilities Design Evaluation and Considerations

Many technical papers have been published on CO_2 flooding from a reservoir standpoint; but, few have ever discussed design considerations of field CO_2 production and injection facilities. This paper will present initial design and installation considerations, design criteria, and initial installation problems associated with Amoco's four West Texas CO_2 projects (Slaughter Estate Unit, Central Mallet Unit, Frazier Unit, Wasson ODC Unit). Additionally, design and operational considerations, based on the experience gained from operating the four CO_2 floods during the last two years, will be discussed for use in future CO_2 facility designs.

Equipment problems which have been experienced during operation, modifications which have been made as a result of experience, and recommended changes for future designs will be discussed in this paper. Actual case histories of operations, equipment design, and equipment problems encountered will be presented. The specific areas to be discussed will include: The CO_2 injection system material selection and layout, CO_2 injection wellhead material selection and configuration, CO_2 injection well downhole equipment, producing wellhead pressure and material requirements, flowline and fluid gathering systems, satellite and central tank battery layout and operation, and the gas collection system layout and material selections.

Special considerations will be given to design details and material specifications that are often overlooked, or not considered. The resulting potential problems and failures of these oversights will be discussed.

TX-Slaughter Sundown (Click Slaughter Sundown to return to table)

(49168) Simulation of a CO_2 Flood in the Slaughter Field with Geostatistical Reservoir Characterization

Texaco has been operating a CO_2 flood in the Sundown Slaughter Unit in Hockley County, Texas since January of 1994. The CO_2 flood was originally justified by analogy with an adjacent CO_2 flood. A CO_2 flood simulation was later done to predict and optimize the performance of the flood. With actual production data from the CO_2 flood available, the simulation forecast was redone and updated. Specific objectives of this new, revised simulation study were to use geostatistical reservoir characterization to improve the representation of reservoir heterogeneity and to use more representative relative permeability curves and residual saturation values.

A team was formed for the new simulation study which included both geologists and engineers with members both from the operating division and Texaco's research organization. Four new geostatistical reservoir models were developed, each with a different level of effective heterogeneity. The basic idea was to adjust the reservoir characterization to improve the CO_2 flood match and forecast. All the new models as well as the old model could be used to match the waterflood history equally well with moderate adjustments in the water-oil relative permeability curves. The correct level of reservoir heterogeneity was not needed to do a waterflood match. However, all the models were not equally valid in matching and predicting CO_2 flood performance. The predicted CO_2 flood performance was substantially different for these models and indicates that a good waterflood history match is not sufficient for a good CO_2 flood prediction.

Having actual CO_2 flood production response data proved to be the key factor in choosing a model with the correct level of heterogeneity and generating an improved CO_2 flood forecast. A successful match of the actual CO_2 flood response could not be obtained with the original model but could be with two of the new geostatistical models. The reservoir heterogeneity in a model must be substantially correct for a successful CO_2 flood match. The predicted CO_2 flood production response was initially fairly close to the actual for these two models, but the match was improved with adjustments of the gas relative permeability curve. In addition, adjusting the gas relative permeability curves to match the initial CO_2 flood response brought the ultimate tertiary oil and CO_2 production forecasts much closer than they had been initially. Adjusting the gas relative permeability curve for a CO_2 flood history match can compensate for moderate, but not large, errors in the reservoir heterogeneity.

This paper describes the methods used for conducting the waterflood and CO_2 flood history matches, for making the CO_2 flood forecast, and for evaluating the different geostatistic realizations. In addition, the important sensitivities of a tertiary CO_2 flood forecast to the reservoir description and the gas relative permeability are discussed and quantified.

(35410) Improved CO_2 Flood Predictions Using 3D Geologic Description and Simulation on the Sundown Slaughter Unit

A fully compositional simulation model using a detailed three-dimensional geologic characterization was constructed for design optimization of the Sundown Slaughter Unit CO_2 flood. The model area comprises 355 acres in the San Andres formation of Slaughter field, located in Hockley County, Texas. Model size and location, three-dimensional geologic description, model construction, and simulation results are discussed. The three-dimensional geologic description provides a novel approach in defining layers of the simulation model. Six different layering systems were selected from the geologic model to represent actual geology in varying detail. Output from the models showed that the number of layers does not have a large impact on primary and secondary oil recovery; however, the number of layers significantly affects tertiary oil recovery. The model with the most layers provides the most realistic tertiary oil recovery forecast.

(30742) Horizontal Well Applications in a Miscible CO_2 Flood, Sundown Slaughter Unit, Hockley County, Texas

Horizontal wells were seen as a potential way to improve CO_2 flood economics by increasing injection rate and improving areal sweep. The effect of horizontal injection wells on vertical sweep in a layered reservoir needed to be determined. Texaco planned to drill two horizontal CO_2 injection wells as a pilot. Nearby observation wells would be used to monitor flow in the reservoir.

More wells were planned as a result of a decision to not operate a CO_2 flood in a densely populated area. Seven wells in the city of Sundown were plugged and abandoned. Three horizontal producers and one horizontal injector were drilled directionally from locations outside town to replace the plugged wells.

This paper summarizes the planning, implementation, and post-drill analysis of these six wells. The seventh and eighth wells have recently been drilled and are mentioned briefly.

TX-South Cowden (Click South Cowden to return to table)

(59691) San Andres and Grayburg Imbibition Reservoirs

Residual oil zones several hundred feet thick are found beneath many San Andres and Grayburg oil reservoirs in the Permian Basin, West Texas, suggesting that these reservoirs once contained a much larger oil volume. Oil has migrated out of these reservoirs, causing the oil-water contact and the zero capillary pressure level (zcpl) to rise, placing the reservoir in imbibition rather than drainage mode. Therefore, saturation profiles should be characterized by the imbibition capillary pressure curve. Imbibition curves have lower water saturations in the productive interval and significantly smaller transition zones than predicted by drainage curves. The reduction in the transition zone is a function of the rise of the zcpl, which is equal to the thickness of the residual oil zone. A more accurate estimate of original oil in place can be obtained if imbibition curves are used to model fluid saturations.

(56609) Use of Sacrificial Agents in CO_2 Foam Flooding Application

One of the factors affecting the economics of CO_2-foam flooding is the loss of the foaming agent by adsorption onto reservoir rocks. As a practical approach for reducing the loss of costly surfactants, the use of sacrificial agents is evaluated in this paper.

Several tests were designed to investigate the feasibility of using lignosulfonate as a sacrificial agent in CO_2-foam flooding. Foam durability tests were conducted to assess the compatibility of lignosulfonate with a primary foaming agent and the resulting foam properties. Flooding experiments were conducted in a composite core, which contained well defined high and low permeability regions, to evaluate the mobility reduction of foam and the oil recovery efficiency. Adsorption experiments were conducted to assess both the loss of the primary foaming agent and of lignosulfonate for further economic evaluation.

The results showed that lignosulfonate itself is a weak foaming agent. When used with a strong or primary foaming agent, it enhanced properties of foams that favorably reduce mobility of CO_2 to correct the nonuniform flow pattern in a heterogeneous porous media. In composite core sample experiments, foams were effective in diverting CO_2 from the high permeability region to the low permeability region and increasing oil recovery efficiency. When lignosulfonate was used as a sacrificial agent, comparable incremental oil recovery could be achieved with concentration of the primary foaming agent reduced by as much as 80%. Considering the cost of reduction and the effectiveness of foams in improving oil recovery, an effective experimental design using lignosulfonate with another primary foaming agent shows potential for economically improving the CO_2-foam flooding process.

(39666) Incorporating Seismic Attribute Porosity into a Flow Model of the Grayburg Reservoir

The Grayburg reservoir of the Foster - South Cowden field has been produced since 1938 and water-flooded since 1962. Production had declined to near abandonment level at the start of this project. The initial approach to construction of the flow model was conventional. Logs and cores provided the basis for a geological model. Production data was assembled and validated as were the few measured pressures taken early in the fields history. Production testing of all wells was initiated with new equipment to provide accurate current production data. Pressure transient testing of all wells was initiated to provide accurate current pressures. History matching pressures and water cuts validated the flow model and the flow model has since guided field operation, subject to the limits imposed by the spacing of the well data which was one reliable well log per 32 acres of reservoir. At this scale compartmentalization, heterogeneity, of the reservoir was obvious, requiring the use of 3-D seismic to define porosity in the area between wells.

The 3-D seismic data set was reprocessed to retain high frequencies, thereby improving vertical resolution to the range of 50 feet. Seismic traces sample areas are 110 by 110 feet (bin size). Seismic inversion model traces exhibit a high degree of correlation to the well log data and a correlation was developed between seismic velocities and porosity for each geologic zone. The correlation was used to develop porosity maps for each zone used in the flow model. The resulting flow model was validated through the history matching process and used to guide the redevelopment of the waterflood.

(37470) The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO_2 WAG Horizontal Injection Wells

Two different methodologies were employed in obtaining injection profile surveys in two CO_2 water-alternating-gas (WAG) horizontal injection wells in the South Cowden Unit (SCU) CO_2 project. Both methods were used once during an initial water injection period to establish a baseline profile. Then, the first method was utilized on both of the horizontal injection wells during a CO_2 injection period. The first method utilized a coiled tubing conveyed, memory-based logging system, including a correlation gamma ray and collar locator log; injection and shut-in temperature, capacitance, flowmeter and pressure gradient; and interface tag. The second method utilized a logging and injection program wherein coiled tubing and wireline were run in the injection well with a Y-block and coiled tubing side-entry assembly attached to the coiled tubing below the spot valve. The tool consisted of a positive and negative gamma ray and temperature tool, and utilized a slug of more than one gallon of radioactive gel rather than the standard injection volume of approximately 50 cc or 1 cc per station. Actual field results are reviewed and the two methodologies discussed for application in CO_2 WAG horizontal injection systems.

(37218) Laboratory Evaluation of Surfactants for CO_2-Foam Applications at the South Cowden Unit

Several laboratory CO_2-foam experiments were performed in South Cowden Unit cores to select a suitable surfactant for possible CO_2-foam application in the South Cowden Unit. Four surfactants Chaser CD-1045, Chaser CD-1050, Foamer NES-25 and Rhodapex CD-128 were evaluated for their foaming ability. Chaser CD-1045 and Rhodapex CD-128 were selected for further testing after an initial screening. These surfactants were tested in co-injection as well as Surfactant Alternating with Gas (SAG) processes at various frontal velocities. The resulting foams exhibited Selective Mobility Reduction (higher resistance factor in higher permeability zones) as well as shear-thinning behavior. While average resistance factor for the foam produced in four sections of a field core was higher for the co-injection of Chaser CD-1045 than Rhodapex CD-128, the later surfactant performed better in the SAG process as well as exhibiting lower adsorption in Baker Dolomite cores. While it is difficult to select Chaser CD-1045 over Rhodapex CD-128 based on laboratory data alone, economics and calculations might select one product over the other. Two adsorption tests performed with Chaser CD-1045 in presence of 250 ppm hydroxy ethyl cellulose as a sacrificial agent did not reduce adsorption of this surfactant.

(36650) Characterization of Diagenetically Altered Carbonate Reservoirs, South Cowden Grayburg Reservoir, West Texas

Much of the difficulty in constructing carbonate reservoir models for fluid-flow simulation results from diagenetic overprinting of depositional permeability patterns. In the South Cowden field, diagenetic effects result in (1) low porosity and permeability in the western and northern areas due to reduction of porosity by means of dolomitization and post-dolomitization compaction, (2) elimination of the petrophysical effects of depositional texture resulting from changes in particle size due to dolomitization, and (3) creation of a touching-vug pore system due to anhydrite dissolution. The extent of anhydrite alteration can be mapped to show three distinct diagenetic areas: those dominated by unaltered, altered, or dissolved anhydrite. Each alteration type has a unique acoustic-porosity transform that can be used to map the diagenetic areas and to calculate porosity when only acoustic logs are available. A single porosity-permeability transform characterizes the areas having unaltered and altered anhydrite, and the depositional stratigraphy is useful in constructing a reservoir model. A more favorable transform characterizes the area of dissolved anhydrite, and depositional stratigraphy is not useful in constructing a reservoir model because of the large effect of the diagenetic overprint.

(35429) Determination of Relative Permeability and Trapped Gas Saturation for Predictions of WAG Performance in the South Cowden CO_2 Flood

CO_2 relative permeability, trapped gas saturation, and hysteresis effects are key parameters in determining injectivity and displacement efficiency in a miscible CO_2 WAG injection project. Coreflood experiments were conducted to determine these parameters for samples from two major lithofacies in the South Cowden reservoir interval. This work was co-funded by DOE under the Class II Oil Program. The data provided key input parameters for simulation modeling and evaluation of the DOE sponsored advanced technology field demonstration project at the South Cowden Unit, Ector County, Texas.

Measurements of residual oil saturations following miscible CO_2 displacement, trapped CO_2 saturations, and endpoint relative permeabilities of CO_2 and water (both before and after CO_2 displacements) are presented for the primary facies. The secondary facies was determined not to be amenable to a WAG injection process. The corefloods were conducted at reservoir conditions (98 F and 1800 psig) using live oil and brine. Magnetic resonance imaging (MRI) was used to screen core plugs for internal, "hidden" heterogeneities prior to flow testing. Trapped gas saturations in the main reservoir facies at South Cowden varied from approximately 20-25 3 % PV. Measured CO_2 relative permeabilities were significantly lower than oil relative permeabilities at comparable water saturations. Water relative permeabilities after CO_2 displacement were appreciably reduced compared with values observed prior to CO_2 injection. The impact of these key parameters on stimulation model predictions of CO_2 flood performance is illustrated using a typical pattern simulation model. Experimental procedures and apparatus are presented along with a method for estimating uncertainties in the trapped gas saturation measurements.

(35222) An Integrated Study of the Grayburg/San Andres Reservoir, Foster and South Cowden Fields, Ector County, Texas

A cooperative study of the Grayburg/San Andres reservoir is being conducted in response to the United States Department of Energy's (DOE) Class II Oil Program. The project is cost shared by Laguna Petroleum Corporation (operator), Latex Resources, Inc. (operator) and the DOE. The purpose of this study is to preserve access to existing wellbores by identifying additional reserves. Production problems associated with shallow shelf carbonate reservoirs are being evaluated by a technical team integrating subsurface geological and engineering data with 3-D seismic data. Engineering analysis, subsurface control from wireline logs, and 3-D seismic data will be integrated using a network of state-of-the-art software on a high performance computer workstation. The results of the integrated effort will be a recommendation for infill drilling locations and the design of an effective waterflood. It is expected that this study will demonstrate a methodology for reservoir characterization and subsequent development of the Grayburg and San Andres reservoirs that is feasible for even small independent operators. The integrated multi-disciplinary approach of reservoir evaluation is relevant to many shallow shelf carbonate reservoirs throughout the United States. Furthermore, this study will provide one of the first public demonstrations of the enhancement of reservoir characterization using high resolution 3-D seismic data. This paper discusses the geological makeup of the Grayburg and San Andres reservoirs and the acquisition, processing, and interpretation of the 3-D seismic data set acquired for the project. The 3-D seismic volume will be utilized for optimization of a reservoir simulation model through a quantitative study to extract reservoir properties from seismic attributes.

(28334) Innovative Approach to CO_2 Project Development Holds Promise for Improving CO_2 Flood Economics in Smaller Fields Nearing Abandonment

The South Cowden (San Andres) Unit is the site selected for one of three mid-term projects to be conducted under the DOE Class II Oil Program for Shallow Shelf Carbonate Reservoirs. The proposed $21 million dollar project is designed to demonstrate the technical and economic viability of an innovative CO_2 flood project development approach. The new approach employs cost-effective advanced reservoir characterization technology as an integral part of a focused development plan utilizing horizontal CO_2 injection wells and centralization of production/injection facilities to optimize CO_2 project economics. If proven successful, this new approach will help improve the economic viability of CO_2 flooding for many older, smaller fields which are or soon will be facing abandonment.

(27658) Proposal for an Integrated Study of the Grayburg/San Andres Reservoir, Foster and South Cowden Fields, Ector County, Texas

A cooperative study of the Grayburg/San Andres reservoir is planned for the Foster and South Cowden Fields, Ector County, Texas under the U.S. Department of Energy's Class II Program for Shallow Shelf Carbonate. The project will utilize existing technology to increase oil production through infill drilling, workovers, and water flood development. Productivity problems associated with a mature shallow shelf carbonate reservoir will be addressed by a multi-disciplinary technical team which integrates high resolution 3-D seismic data, reservoir characterization techniques, and 3-D reservoir simulation.

A 3-D seismic survey designed specifically for imaging the Grayburg/San Andres interval of the Foster and South Cowden fields will be acquired. A high performance computer workstation will then be used to integrate existing subsurface geological and engineering data with the 3-D seismic data for a detailed evaluation of sequence stratigraphy and facies relationships. Subsequently, a 3-D reservoir simulation model will use the results to help define flow units within the reservoir. A field demonstration of infill drilling and water flood development will follow.

The high resolution 3-D seismic survey is expected to resolve changes in the subsurface on the megascopic scale, allowing for correlation of petrophysical properties and stratigraphic information between boreholes. This information will be helpful in mapping porosity zones, permeability barriers, and "thief" zones within the reservoir.

Field operators involved in the project include a major oil company and a small independent operator which will be working together through a cooperative study agreement. It is expected that this study will demonstrate a methodology of reservoir characterization and subsequent development of the Grayburg/San Andres reservoir which is feasible for independent operators. Furthermore, it will provide one of the first public demonstrations of the enhancement of reservoir characterization using high resolution 3-D seismic data.

(27655) Design and Implementation of a CO_2 Flood Utilizing Advanced Reservoir Characterization and Horizontal Injection Wells in a Shallow Shelf Carbonate

The South Cowden (San Andres) Unit is the site selected for one of three mid-term projects to be conducted under the DOE Class II Oil Program for Shallow Shelf Carbonate Reservoirs. The proposed $20 million South Cowden Advanced Technology Demonstration Project is designed to demonstrate the technical and economic viability of an innovative CO_2 flood project development approach. The new approach employs cost-effective advanced reservoir characterization technology as an integral part of a focused development plan utilizing horizontal CO_2 injection wells and centralization of production/injection facilities to improve CO_2 project economics. This new approach could open up CO_2 flooding for many of the older, smaller fields which are or soon will be facing abandonment This paper is the first in a series of papers intended to document the technical premises, planning, implementation, and operation of the South Cowden Advanced CO_2 Flood Technology Demonstration Project over the life of the project This first paper will present the overall project concept, technical premises, and performance expectations which will provide the foundation for subsequent work.

The South Cowden Unit has been successfully waterflooded and is now nearing its economic limit and eventual abandonment. The commonly encountered problems of limited reservoir size and lack of wellbores suitable for use as CO_2 injectors makes conventional CO_2 flood pattern development uneconomic in this Unit. The paper illustrates how the proposed project development approach using multiple horizontal CO_2 injection wells drilled from a central location can significantly improve project economics. Under the proposed development scheme, the number and total cost of injection wells and associated equipment will be reduced Centralization of production, gas recycle, and injection facilities will minimize the costs associated with gas handling and distribution systems. In addition to cost savings, use of horizontal CO_2 injection wells also holds promise for improving CO_2 flood performance by increasing areal sweep efficiency.

One key to realizing these technical and economic advantages lies in tailoring the number, length, orientation, and completion design of the horizontal wells to the specific reservoir geology.

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TX-South Pierce and Liberty (Click South Pierce and Liberty to return to table)

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TX-South Welch (Click South Welch to return to table)

(27676) CO_2 Operating Plan, South Welch Unit, Dawson County, Texas

The South Welch Unit of the Welch Field commenced full scale injection of CO_2 beginning in September of 1993. The flood design was based on the performance of a 180 acre pilot conducted from 1982 to 1987. A compositional model study of the pilot performance was used to design a CO_2 processing facility and the full scale flood operating approach. Primary, secondary and tertiary performance matching were used to verify the reservoir and process description and to forecast performance under a full field scenario. Scaleup was based on floodable pay from the modeled area related to the remaining areas under consideration for flood.

Reservoir simulation and economic analysis were used to investigate water alternating gas (WAG) cycle lengths, WAG ratio, and total slug sizes. Phasing of areas was coupled to level plant loading considerations, water handling limits, and short term profitability to develop an operating plan for the Unit.

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields

CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987

Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(12664) CO_2 Miscible Flooding Evaluation of the South Welch Unit, Welch San Andres Field

The South Welch Unit, in Dawson County, Texas, was selected as a miscible flooding candidate in 1981 based on the recommendation of a feasibility study. The central 300 acres (1,214 Mm) of the unit were designated as the Phase One area, and infill drilling of this area was begun in 1981. CO 9 injection was initiated in February of 1982 with CO_2, trucked to the location in liquid form. Simulations were made to predict the recovery from the Phase One area under predict the recovery from the Phase One area under several production methods. These methods included:

20% IHCPV slug CO_2 injected continuously 20% IHCPV slug CO_2 injected using a 2:1 4 cycle WAG
25% IHCPV slug CO_2 injected using a 2:1 3 cycle WAG
Continued waterflooding on 20 acre line drive patterns

All simulations were made with the current CO_2 supply limitations taken into consideration. The 25% slug, 2:1 5 cycle WAG case is the optimum mode of operation based on sensitivity studies.

TX-Spraberry Trend (Click Spraberry Trend to return to table)

(10759) The Effect of Lateral Anisotrophy on Flood Pattern Dimensions and Orientation

This paper compares different flood pattern orientations and dimensions for isotropic and anisotropic reservoirs in order to determine the optimum waterflood pattern in the presence of directional permeability. This was accomplished by simulating the reservoir performance for several patterns with a 5-point black oil simulator. The patterns simulated patterns with a 5-point black oil simulator. The patterns simulated include the: 1) 5-spot, 2) inverted 9-spot, 3) modified 9-spot (an inverted 9-spot pattern with two producing wells eliminated), and 4) direct line drive. For simplification, unit mobility ratio and miscible displacement were used to model the displacement of oil by water, although the conclusions are identical for a mobility ratio different from one and an immiscible displacement. Each pattern was tested with the dimensions being both square and elongated (four times the length in one direction). Each of these sets of patterns were simulated as isotropic and anisotropic reservoirs. The patterns were elongated in the direction of and in the direction opposite to the high permeability trend. Included is a discussion of results of each pattern tested and conclusions as to the optimum waterflood pattern for anisotropic reservoirs. These conclusions may be applied to any reservoirs having directional permeability. These results may be realized with any injection scheme such as CO_2 injection, natural gas injection and steam flooding.

(405) Large Scale Waterflood Performances Sprayberry Field, West Texas

First response to large scale water flood in the fractured milli-darcy Spraberry sand has led to a new unique cyclic operation. Capacity water injection is used to restore reservoir pressure. This is followed by a few months production without water injection and the cycle repeated. Expansion of the oil, rock and water during pressure decline expels part of the fluids but capillary forces hold much of the injected water in the rock. Field performance has proved this cyclic operation is capable of producing oil from the matrix rock at least fifty per cent faster and with lower water percentage than is imbibition of water at stable reservoir pressure.

TX-TwoFreds (Click Twofreds to return to table)

(26614) Update Case History: Performance of the Twofreds Tertiary CO_2 Project
The performance of the first Texas field-scale tertiary CO_2 injection project in a sandstone formation is updated. The Twofreds tertiary CO_2 injection project was developed in two phases. The east side of the reservoir was initiated in February 1974 and is now essentially completed. Expansion to the west side started in the early 80's. Detailed evaluation of the actual performance of the east side CO_2 flood will be presented along with operations, design, and monitoring considerations.

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields
CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(18977) Summary Results of CO_2 EOR Field Tests, 1972-1987
Since the early 1970s, numerous presentations have been made and articles written about pilot tests and field-scale enhanced oil recovery projects using carbon dioxide (CO_2) as a solvent. This paper summarizes publicly available data on 30 paper summarizes publicly available data on 30 projects. The use of CO_2 has grown significantly projects. The use of CO_2 has grown significantly since the early-1980s, especially in the Permian Basin, as reliable supplies of CO_2 became more available. Today, even with depressed crude oil markets, the use of CO_2 continues to grow. The use of CO_2 in the Rocky Mountain region is increasing, primarily among those with prior CO_2 flooding primarily among those with prior CO_2 flooding experience in the Permian Basin. As the demand for CO_2 increases in the Rocky Mountains, so will the supply, and the same growth experienced in the Permian Basin should be seen. As with any major Permian Basin should be seen. As with any major project in the oil industry, the enhanced recovery project in the oil industry, the enhanced recovery of oil requires thorough advance planning to determine the optimum EOR method. This summary of CO_2 projects is intended to provide a brief on each project, describe the reservoir parameters, and project, describe the reservoir parameters, and review the conclusions of the individual authors, in addition to providing a quick reference of available papers to which those interested may turn for greater detail. Since the use of CO_2 has been successfully tried in a wide range of reservoirs and under a variety of operating conditions, the application of CO_2 in Rocky Mountain reservoirs should be every bit as successful as it has been elsewhere.

(14439) Performance of the Twofreds CO_2 Injection Project
The Twofreds (Delaware) Field, located in Loving, Reeves, and Ward Counties, Texas, is operated by HNG Fossil Fuels Company and has been under continuous CO_2 injection since February, 1974. The field was nearing its economic limit under waterflooding when the CO_2 project was initiated. In the 11 years since tertiary injection began, total field oil production has been increased from 170 bbl/D (27.0 m^3/d) to over 920 bbl/D (146 m^3/d). Tertiary oil recovery to date has been over 2.5 X 16-6 barrels (0.397 X 10 m^3) of oil. This mature, commercial-scale project offers a unique opportunity for the evaluation of long-term effects of practical CO_2 operations. The field currently produces 923 bbl/D (147 m^3/d) has cumulatively produced 11.2 X 10 barrels (1.78 X 10 m^3) of water since discovery in 1957.

The Twofreds (Delaware) Field produced under primary recovery from January, 1957 until January, primary recovery from January, 1957 until January, 1963 when it became the first unitized water injection project in the Delaware Basin. In February, 1974, Twofreds became the first field-scale tertiary CO_2 injection project in a sandstone formation in Texas. The majority of the field (98.6%) had been purchased for tertiary purposes by HNG Fossil Fuels purchased for tertiary purposes by HNG Fossil Fuels purchased for tertiary USA, Inc. and RGS (Ritchie, Gerard and Stanberry). Atlantic Richfield Company (ARCO), with the remaining 1.4%, was the only original owner that elected to maintain their interest in the field, and joined in the operation. Carbon dioxide for the Twofreds Field is obtained from Intratex. Gas Company's

MiVida Gas Processing Plant located 9.64 (15.5 km) miles from the field. Exhaust gas injection was initiated in October, 1980 to supplement the CO_2 injection. This additional injection made possible the expansion of the project to include the entire field. project to include the entire field. This paper reviews the reservoir performance during primary, secondary, and tertiary operations. A detailed evaluation is made of the field's response to CO_2 injection, and operational considerations are discussed.

(8382) Twofreds Field a Tertiary Oil Recovery Project
The Twofreds Delaware Sand Reservoir was discovered in 1957 and developed as a water-flood unit in 1963. By 1973, after a moderately successful water-flood, the production rate had declined to near economic limit. Carbon Dioxide injection for oil recovery was instigated in 1974, therefore, oil recovery since 1974 represents tertiary oil recovery after water-flooding. This paper discusses the actual application of CO_2 injection procedures and the field performance for the 5-year period since CO_2 injection was started. Performance to date appears successful in recovering additional oil from reservoirs of this type.

(1792) Pressure Maintenance by Water Injection In the Twofreds (Delaware) Field Unit
The Twofreds [Delaware] field unit is located in the Delaware Basin in Loving, Ward and Reeves Counties, Tex. Production is from the upper sand of the Bell Canyon section of the Delaware Mountain group at a depth of 4,820 ft. A pilot water injection project was started in the unit in 1963 and excellent results led to full-scale injection in 1966. Substantial oil production response has occurred in areas with water saturations as high as 45 percent. No water breakthrough has occurred anywhere in the unit. Performance of the Twofreds unit to date indicates that an oil bank can be built and maintained in the high water saturation Delaware sand, that a satisfactory volumetric sweep efficiency will be achieved, and that abnormal injectivity decline will not be a problem.

TX-University Waddell (Click University Waddell to return to table)
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TX-Waddell (Click Waddell to return to table)
(1146) Pressure Maintenance by Bottom-Water Injection in a Massive San Andres Dolomite Reservoir
The Waddell field is being pressure maintained by the injection of Hendrick reef salt water, oil a peripheral pattern, below the oil-water contact. The reservoir is a San Andres dolomite of Permian Age, occurring at approximately 3,450 ft. The original producing mechanism was dissolved-gas drive. Reservoir Pressure decline and increasing gas-oil ratios indicated the need for pressure maintenance to maximize the oil recovery. Performance to date, as influenced by water injection, has been very encouraging. During six years of pressure maintenance operations, the reservoir pressure has increased from 843 to 1,171 psig. The gas-oil ratio during this period has dropped from 1,100 to 456 scf/bbl. The dissolved gas-oil ratio, at a saturation pressure of 1,134 psig, is 484 scf/bbl. To date, 41.9 million bbl of water have been injected. The current fluid withdrawals are cutting 10 per cent water. Total ultimate recovery will be increased appreciably as a result of pressure maintenance operations. The actual performance to date is compared to an estimated performance to date under continued primary depletion.

TX-Wasson (Click Wasson to return to table)
(71496) Physical Effects of WAG Fluids on Carbonate Core Plugs
It is a given that carbonate mineral dissolution and deposition occur in a formation in geologic time and are expected to some degree in carbon dioxide (CO_2) floods. Water-alternating-gas (WAG) core flood experiments conducted on limestone and dolomite core plugs confirm that these processes can occur over relatively short time periods (hours to days) and in close proximity to each other.

(24185) CO_2 Miscible Flood Simulation Study, Roberts Unit, Wasson Field, Yoakum County, Texas
This paper describes the procedures of a simulation study to design an optimum CO_2 flood process for the Texaco operated Roberts Unit located in the Wasson Field, Yoakum County, Texas. The designing process includes geological study to define flow units, CO_2 target area selection, model area determination, fluid characterization, model calibration by history matching waterflood performance, compositional simulation forecasting for tertiary recovery, and economic analyses.

An equation-of-state (EOS) compositional simulator was used for both waterflood history matching and CO_2 flood predictions.

Phase behavior of the CO_2/Hydrocarbon system was calibrated by matching laboratory PVT test results. Tertiary forecasts were run for various continuous, water-alternating-gas (WAG) and hybrid modes of operation. Simulation results were scaled to represent the entire Roberts Unit CO_2 target area. An economic indicator was then used to determine the optimum method of CO_2 injection.

(24111) Prediction of CO_2/Crude Oil Phase Behavior Using Supercritical Fluid Chromatography
In this paper, we describe a method for characterization of crude oils for predictions of phase behavior of CO_2/crude oil mixtures with an equation of state (EOS). The method includes the use of supercritical fluid chromatography (SFC) with CO_2 as the carrier fluid. Pressure-composition diagrams calculated using the Peng-Robinson EOS and this characterization scheme agree well with PVT observations. The advantage of this technique is that it produces predictions of the phase behavior of CO_2/crude oil mixtures with much less experimental effort than is required to perform PVT experiments.

(23974) Analysis of Tertiary Injectivity of Carbon Dioxide
The most important conclusion is that the mixing phenomenon due to dispersion, crossflow and viscous instability that models neglect can significantly influence injectivity. The results indicate that three-phase flow of gas, oil and brine needs to be modeled and that, contrary to the conclusions of other investigators, three-phase flow effects can have important influences on injectivity, even when CO_2 is injected above its MMP. In addition, the most sensitive relative permeability parameters for reservoir-scale, tertiary CO_2 flooding conditions in parameters for reservoir-scale, tertiary CO_2 flooding conditions in the presence of correlated permeability heterogeneity are identified. Sensitivity to the relative permeability parameters can also be substantial, even at low permeability contrast. The results presented in this paper are particularly pertinent to the hybrid-WAG displacement process since they provide information about the first cycle of CO_2 injection.

(19783) An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs
In this paper we present the results of a technical and an economic evaluation of waterflood infill drillings in fourteen Clearfork and eleven San Andres carbonate reservoirs in West Texas. The initial waterflood recovery efficiency and the infill drilling waterflood recovery efficiency were estimated from decline curve analyses. The economic analysis was performed to evaluate the relative profitability of the waterflood infill drilling operations.

For Clearfork units, the estimated initial waterflood recovery efficiency ranged from 9.54 to 32.19% of original oil in place (N) with a medium of 17.75%N; and the infill drilling waterflood recovery efficiency ranged from 13.09 to 52.56%N with a medium of 25.53%N. The medium increase in oil recovery by infill drilling was 7.78%N. For San Andres units, the initial waterflood recovery efficiency ranged from 10.68 to 39.03%N with a medium of 19.97%N; and the infill drilling waterflood recovery efficiency ranged from 13.73 to 44.58%N with a medium of 31.82%N. The medium increase in oil recovery by infill drilling was 11.38%N.

A multi-linear regression analysis was used to establish regression models correlating the initial waterflood and the infill drilling waterflood recovery efficiencies to reservoir and process parameters. For the Clearfork units, the process parameters. For the Clearfork units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 20.39%N and 3.19%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 29.25%N and 2.48%N, respectively. The average increase in oil recovery by infill drilling was 8.86%N. For the San Andres units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 22.09%N and 1. 45%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 32.23%N and 2.73%N, respectively. The average increase in oil recovery by infill drilling was 10.14%N.

Two cases were studied in the economic analyses. Case I economic analysis used past and projected production schedule and economic projected production schedule and economic parameters. For the Clearfork units, the rate of parameters. For the Clearfork units, the rate of return ranged from 18.37% to 125.2% with a mean of 53.3%. The payout ranged from 1.22 years to 6.58 years with a mean of 3.14 years. For the San Andres units, the rate of return ranged from 20.58% to 500.0% with a mean of 157.0%. The payout ranged from 0.36 to 5.43 years with a mean payout ranged from 0.36 to 5.43 years with a mean of 1.77 years.

Case II economic analysis used past and projected production data as though the projects projected production data as though the projects were initiated in January 1988. The base crude oil price of $17.50/STB was assumed in the analyses. For the Clearfork units, the rate of return ranged from 11.41% to 98.80% with a mean of 40.4%. The payout ranged from 1.45 to 6.42 years with a mean of 3.53 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 4.28 years and 3.13 years using $22.50/STB. For the San Andres units, the rate of return ranged from 20.58% to 500.00% with a mean of 157.00%. The payout ranged from 2.36 to 4.91 years with a mean of 2.3 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 2.18 years and 2.00 years using $22.50/STB.

(19666) The Effects of Waterflooding on Reservoir Properties and Producing Operations: Applications for Geochemical Modeling

Detailed analysis of core samples from San Andres Formation dolomites and scale samples from production wells in two Permian Basin reservoirs production wells in two Permian Basin reservoirs document the effects waterflooding has had on the Permian (Guadalupian) Age reservoirs. Anhydrite Permian (Guadalupian) Age reservoirs. Anhydrite dissolution adjacent to an injection well and the precipitation of sulfate scale in producing wells precipitation of sulfate scale in producing wells and equipment are shown to be unequivocally attributable to waterflooding. Geochemical modeling has been used to determine water/water and rock/water compatibilities so that proper water handling techniques could be implemented to improve operational efficiencies and reduce the potential for reservoir and equipment damage potential for reservoir and equipment damage caused by dissolution and/or precipitation of minerals.

(19596) Outcrop/Subsurface Comparisons of Heterogeneity in the San Andres Formation

An integrated outcrop and subsurface study of permeability variations in the San Andres formation demonstrates the extreme heterogeneity present in this economically important carbonate horizon. Permeability measurements were made with a field permeameter and were Permeability measurements were made with a field permeameter and were compared to subsurface core data. Geostatistical techniques were used to predict variability and scales of spatial correlation. Measured permeability showed substantial variability within units arranged in permeability showed substantial variability within units arranged in three correlation scales. Outcrop permeability data exhibited no marked permeability anisotropy in predicted spatial correlation length. Several permeability anisotropy in predicted spatial correlation length. Several scales of spatial variability have been observed in an outcrop section, with subsurface results in agreement.

(16716) The Effects of CO_2 Flooding on Wettability of West Texas Dolomitic Formations

Reduced water injectivity after CO_2 injection has frequently occurred in West Texas oil fields. One explanation proposed for this phenomenon was a change in rock wettability by the CO_2 and crude oil miscible bank. This paper describes an experimental study to determine the effects Of CO_2 flooding on the wettability of West Texas dolomitic cores.

This study examined the relative permeability characteristics of fresh-state San Andres and Grayburg dolomite core samples before and after passing a crude Oil/CO_2 miscible front through the test core. Changes in the relative permeability characteristics were used to infer the effects Of CO_2 flooding on rock wettability. The cores chosen were intermediate oil wet, intermediate, and intermediate water wet. The results showed that the cores became slightly more water wet. However, this change in wettability was near the limit of statistical confidence. Some data suggests that the tendency to becoming water wet was cause by slight rock dissolution by the CO_2 and brine. Some observations concerning the compatibility of brines used in laboratory core floods with dolomites containing anhydrite are discussed.

(15037) An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units
This paper examines the profitability of past waterflood infill drilling programs. The past waterflood infill drilling programs. The project data is from the Texas Railroad project data is from the Texas Railroad Commission files, and includes large carbonate and sandstone reservoirs such as the Wasson (San Andres) Field and the Big Wells (San Miguel) Field. All of the reservoirs were subject of intensive reservoir engineering and geologic study by the oil companies prior to initiation of the infill drilling project. The permeability of the reservoirs averages 8.8 md and ranges permeability of the reservoirs averages 8.8 md and ranges from .65 md to 27 md. The porosity averages 10% and ranges from 7% to 18.6%. The depths range from 1220 to 1525 meters with the deepest at 2130 meters.

Because of the large capital cost required for drilling and operating additional wells, it was not clear whether the infill drilling programs had recovered enough additional oil to be programs had recovered enough additional oil to be good investments. In spite of the variability of external factors such as the cost of wells and price of oil, all of the projects studied obtained at least an acceptable economic return. the average discounted profit to investment ratio was 2.0, and the average incremental oil per well was 15 thousand cubic meters. Most of per well was 15 thousand cubic meters. Most of the calculated rates of return exceeded 30%. The net present value at 15% after taxes ranged from $580,000 to $32 million dollars. Thus these waterflood infill drilling projects have generally been very successful.

(14288) A CO_2 Injection Measurement and Control System
Advances in microcomputer technology have heralded a new era in oil field automation. A novel measurement and control system has been implemented on the carbon dioxide injection wells in the Slaughter and Wasson Fields operated by Amoco Production Company. The heart of this system is a solar powered microprocessor based Remote Telemetry Unit which senses the necessary input parameters, performs the calculations necessary to measure the rate and pressure at which carbon dioxide is being injected, pressure at which carbon dioxide is being injected, controls the position of a ball valve to maintain the desired flow rate and pressure, and sends selected information to a central automation computer for alarm and reporting purposes. The purpose of this paper is to describe the electronic purpose of this paper is to describe the electronic hardware, the end devices, control element, and software that was used to implement this function.

(13116) Effect of Phase Behavior on CO_2 Displacement Efficiency at Low Temperatures: Model Studies With an Equation of State
In this paper, we examine the use of an equation of state (EOS) to predict the phase behavior of CO_2/crude-oil systems at low temperatures. An adequate match of the experimental pressure/composition diagrams of a dead oil and two recombined oils from the Wasson field at 90 deg. F [32 deg. C] is obtained. The incorporation of three-phase flash calculations in a compositional model is described. The model is used to simulate CO_2 slim-tube displacements and yields results that are consistent with experimental observations.

(11592) CO_2 Flooding: Its Time Has Come
Several U.S. DOE, Natl. Petroleum Council, Federal Energy Admin., and private investigations identified CO_2 sources and supplies, separation processes, and transportation facilities. These 25 years of effort are now beginning to show results. Current field applications are continuing and expanding. A 1982 survey revealed a 65% increase in the number of CO_2 projects over 1980. Four large pipelines have been started to bring CO_2 from distant pipelines have been started to bring CO_2 from distant (200 to 400 miles) sources. Colorado and New Mexico gas fields will supply CO_2 for miscible flooding in the Wasson and other fields in west Texas. Two other pipelines will serve the Purdy Springer and East pipelines will serve the Purdy Springer and East Velma fields in Oklahoma, and the Little Creek and West Mallaleiv fields in Mississippi. CO_2 available from refineries and fertilizer plants in the Los Angeles basin has been targeted for immiscible flooding of local heavy-oil reservoirs. Studies have been made of CO_2 pipelines to bring additional CO_2 from Utah and New Mexico to the basin. Although the economic recession and worldwide oil glut have slowed its progress, CO_2 flooding's time has come.

(11125) Interpretation of Pressure-Composition Phase Diagrams for CO_2/Crude-Oil Systems

Results of single-contact phase behavior studies for CO_2/crude-oil mixtures often are presented as pressure-composition (P-X) phase diagrams. In such diagrams, regions of pressure and CO_2 mole fraction for which more than one phase forms can be identified easily. Phase diagrams for CO_2/crude-oil phase forms can be identified easily. Phase diagrams for CO_2/crude-oil systems can be quite complex, however, since under some conditions such mixtures can form a liquid and a vapor, two liquid phases, or two liquids and a vapor in equilibrium. This paper examines P-X diagrams for two ternary systems, CO_2/propane/hexadecane and CO_2/methane/hexadecane, and describes transitions from one diagram to another that occur with changes in system temperature or changes in oil composition.

Nine experimentally determined P-X diagrams are presented for mixtures of Wasson crude oil with CO_2. Three different oils, stock-tank oil, stock-tank oil plus 312 scf/bbl [560 std m3/m3] solution gas, and stock-tank oil plus 602 scf/bbl [1084 std m3/m3] solution gas, were studied at three temperatures, 90, 105, and 120F [32, 41, and 49C]. Comparison of the resulting phase diagrams with those discussed for the simpler ternary systems indicates that the principal features of the crude oil phase diagrams are qualitatively consistent with those of the ternary systems. The results of the CO_2/crude-oil experiments indicate that for low-temperature systems (below about 120F [49C]), the extrapolated vapor pressure (EVP) Of CO_2 is a good estimate of the pressure required to pressure (EVP) Of CO_2 is a good estimate of the pressure required to produce a dense, relatively incompressible CO_2-rich phase that can extract produce a dense, relatively incompressible CO_2-rich phase that can extract hydrocarbons efficiently from a crude oil. Hence, in the absence of other experimental evidence, the EVP curve can be used as a rough estimate of the minimum miscibility pressure (MMP) for low-temperature reservoirs.

(10686) An Investigation of Phase Behavior-Macroscopic Bypassing Interaction in CO_2 Flooding
CO_2-crude coreflood experiments and high-resolution 2-D CO_2-crude displacement simulations in which viscous fingering is represented explicitly suggest that there is a synergistic interaction between multiple-contact CO_2-crude phase behavior and macroscopic bypassing that causes the "ultimate" oil recovery (when the system has been swept) to be lower in the unstable case than in the stable case. Assuming this effect is present in field applications of CO_2 flooding, then corefloods in which fingering is absent, for whatever reason, should not be used as direct indicators of field-scale displacement efficiency since they will yield optimistic predictions, all other factors being equal between the laboratory and the field.

(8367) The Effect of Phase Behavior on CO_2-Flood Displacement Efficiency
The relationship between phase behavior and displacement efficiency (meaning here, recovery efficiency in the absence of any bypassing) as regards the displacement of Wasson crude oil by CO_2 is examined at two different pressures--the lower pressure the one at which three coexisting pressure the one at which three coexisting hydrocarbon phases are encountered. At both pressures, experimental phase behavior data pressures, experimental phase behavior data comprising primarily phase volume fractions observed in both single- and multiple-contact experiments are presented. Pseudoternary representations of the presented. Pseudoternary representations of the phase behavior are incorporated into a simple, phase behavior are incorporated into a simple, one-dimensional, finite-difference simulator to relate the phase behavior to displacement efficiency. At the appropriate dispersion level, displacement efficiencies computed with the model are consistent with high oil-recovery efficiencies obtained experimentally in slim-tube displacements, and indicate that the displacement efficiency of the process (again, in the absence of bypassing) should be high in certain consolidated media as well.

(3570) Use of the SP Log in Waterflood Surveillance
SP logs recorded in a West Texas waterflood exhibited enough sensitivity to indicate zones taking fluids in open-hole wells and in wells lined with fiber glass. These surveys are logged both when the wells are shut in and during injection, and the difference in values is the electrokinetic component of the measurable spontaneous potential, which is proportional to the rate of flow into each zone.

(2472) Three Porosity Movable Oil Plot Vs Single Porosity Movable Oil Plot to Improve Completion Results in the Wasson Field
Texas Pacific Oil Co. has used the composite three porosity tool lithology movable oil plot on eight wells in the Wasson Northeast Clearfork field in Yoakum County, Tex. Single porosity movable oil plots have been used on porosity movable oil plots have been used on five wells. Results of the completions have been

good. The Clearfork formation is a Permian-age carbonate reservoir composed of Permian-age carbonate reservoir composed of dolomite and anhydrite and containing lesser amounts of gypsum, silica and limestone. Sonic, density and neutron logs all respond differently to porosity as the lithology varies. A mathematical solution may be used to define the fractions of major lithologic components and calculate the correct porosity. A comparison of single porosity movable oil plots has indicated that the sidewall neutron plots has indicated that the sidewall neutron log presents the most accurate porosity log when only one porosity tool is to be used. The laterolog and microlaterolog are used to determine the movable oil relationship.

TX-Wasson Cornell (Click Wasson Cornell to return to table)

(16854) Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas

This paper presents the results of an economic analysis of infill drilling in 16 carbonate oil reservoirs located in West Texas. The economic analysis included the evaluation of incremental waterflooding recovery over primary and infill drilling recovery over initial waterflooding.

Because of limited field and economic data available for this study, many assumptions were made to complete the economic evaluations. Two major cases of economic evaluation were performed: Case 1 used the past production and economic data to 1986 and the projection of these data from 1986 on to the assumed economic limit, and Case II used the past infill production data as if the projects were initiated in January 1986 and on to the assumed economic limit.

Results showed that about 6811 of the infill drilling projects studied had an infill drilling incremental payout of less than two years with a incremental discounted cash flow rate of greater than 20%. Only 37% of the projects studied had a waterflood incremental economics with the same criteria. Decreasing the well spacing generally decreased the infill drilling incremental payout and increased the incremental cash flow rate of return. As the OOIP/WS (well spacing) increased, the general trend showed an increasing infill drilling incremental net present value.

Results from Case II studies showed that for a $15/STB ($94/m 3) oil price in 1986, about 68% of the infill drilling projects studied had an infill drilling incremental payout of less than two years with an incremental discounted cash flow rate of return greater than 20%. As the OOIP/WS increased, the general trend also showed an increasing infill drilling incremental net present value. When the oil price in 1986 was increased from $15/STB ($94/m 3) to) $25/STB 0157/m 3), the increase " the incremental net present value (INPV) was substantial. For example at a value of 20 for OOIP/WS (Means Field/San Andres), the INPV increased from $76 MM to $122 MM.

(15037) An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units

This paper examines the profitability of past waterflood infill drilling programs. The past waterflood infill drilling programs. The project data is from the Texas Railroad project data is from the Texas Railroad Commission files, and includes large carbonate and sandstone reservoirs such as the Wasson (San Andres) Field and the Big Wells (San Miguel) Field. All of the reservoirs were subject of intensive reservoir engineering and geologic study by the oil companies prior to initiation of the infill drilling project. The permeability of the reservoirs averages 8.8 md and ranges permeability of the reservoirs averages 8.8 md and ranges from .65 md to 27 md. The porosity averages 10% and ranges from 7% to 18.6%. The depths range from 1220 to 1525 meters with the deepest at 2130 meters.

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(10292) CO_2 Flood Performance Evaluation for the Cornell Unit, Wasson San Andres Field

A numerical reservoir simulator has been used to predict CO_2 enhanced oil recovery (EOR) performance for two process designs, either of which could be implemented at process designs, either of which could be implemented at the Cornell Unit, Wasson San Andres field. The two CO_2 displacement processes examined are a straight CO_2 slug followed by continuous water injection, and a water-alternating-gas (WAG) process with CO_2, followed by continuous water injection.

Predicted recovery performances were found sensitive to viscous, capillary, and gravity-driven crossflow, as well as to reservoir stratification. Hence, evaluation of alternative process designs was influenced strongly by assumed values of effective vertical permeability within continuous pay intervals, even though the vertical permeability between major pay intervals is effectively permeability between major pay intervals is effectively zero.

Work involving a no-crossflow stratification model of the Wasson pay suggested that a straight CO_2 slug process would be preferable to a WAG process. On the other process would be preferable to a WAG process. On the other hand, work with a stratification model that allowed interzone crossflow indicated that recovery could be improved significantly for a given size CO_2 slug by means of a WAG process.

(9762) Success of a High-Friction Diverting Gel in Acid Stimulation of a Carbonate Reservoir - Cornell Unit, San Andres Field

High-friction gel (HFG) is a fluid that exhibits unusual shear stress characteristics that make it well suited as a diverting agent for well stimulation procedures. It is being pumped into the formation of the Cornell Unit to divert acid to other portions of the formation. Injection wells that have been acid stimulated using HFG as a diverting agent have displayed better vertical sweep efficiency than those using straddle packers or benzoic acid flakes to divert acid.

TX-Wasson Denver (Click Wasson Denver to return to table)

(59548) Denver Unit Infill Drilling and Pattern Reconfiguration Program

The Denver Unit CO_2 flood, one of the largest in the world, was implemented in 1984. CO_2 injection was subsequently expanded in 1989 and again in 1991. By 1994, this 10 year old CO_2 flood had a well-established decline in its production function. Through infill drilling and pattern conversion, the mature CO_2 flood in the Denver Unit was revived. The redevelopment program depended heavily on the reservoir simulation technology and the multi-discipline team concept to ensure its technical and economical success. Thus far, the redevelopment program has added approximately 6600 barrels of oil per day to the existing production at peak rate, and approximately 14.2 million barrels of oil to the ultimate reserves. This report reviews the infill drilling and pattern reconfiguration simulation studies, the pilot program, which led to full field development, and the results of the project to date.

(56549) Reservoir Characterization and Development Plan of the Wasson San Andres Denver Unit Gas Cap

A plan has been developed to produce the Wasson San Andres Denver Unit Gas Cap reserves without adversely affecting the existing tertiary, CO_2 flood of the oil column. This paper: (1) describes the reservoir characterization studies validating hydraulic isolation between the uppermost San Andres gas bearing zones and oil-bearing zones currently under water and CO_2 flooding, (2) details the field testing programs, including extensive PTA work and fracture control modeling, that proved technical viability of producing the gas cap without effecting the oil column, (3) details the Wasson field, 3-D, fully compositional, simulation model used for predicting effects on the oil column and developing gas production forecasts and (4) highlights plans for construction and installation of gas gathering facilities adjoined with the existing Denver Unit CO_2 recovery plant and/or third party processors. The development plan was approved April 14, 1998 by the Texas Railroad Commission, who agrees that no loss in oil recovery will result from producing the stratigraphic gas-bearing zone termed the First Porosity in the Wasson San Andres formation.

(29116) Field-Scale CO_2 Flood Simulations and Their Impact on the Performance of the Wasson Denver Unit
Recent advances in software and hardware technology have made possible the development of field-scale, fully compositional CO_2 flood simulations capable of capturing areal variations in performance on an individual well basis. This paper first describes the general methodology developed, including key elements used to construct such large models, followed by the validation of this approach. Two modeling studies conducted on the Wasson Denver Unit are then presented to highlight several of the significant outcomes realized so far: high-grading the profitability of new CO_2 projects, pinpointing best well candidates to return to production, identifying infill and horizontal drilling locations, and identifying and quantifying injectant losses.

(27674) The Denver Unit CO_2 Flood Transforms Former Waterflood Injectors into Oil Producers
The profitable conversion of off pattern water injectors to production wells is possible in CO_2 floods. An initial water production period often precedes the breakthrough of oil into such injector-to-producer (ITP) conversions. At the Wasson (San Andres) Denver Unit in West Texas, time to economic oil production and initial economic oil production rates may be estimated by simulation or analog methods. Performance data from more than 25 wells is discussed in this paper.

(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs
Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacings. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

(26391) CO_2 EOR Economics for Small-to-Medium-Size Fields
CO_2 projects undertaken in the past have generally been large fields that benefited from economy of scale and substantial remaining life. Future CO_2 Projects will generally not have these advantages. However, since the CO_2 source and distribution infrastructure are in place, many smaller oil fields may be candidates for CO_2 enhanced oil recovery (EOR). This paper investigates the economic viability of conducting CO_2 EOR operations in small to medium-size fields under today's market conditions. The evaluation uses actual production data from a representative CO_2 project, current costs to equip the field for CO_2 operations, and operating costs in the actual range of ongoing projects. Sensitivity to these factors plus depth and porosity acre-feet are discussed. The economic impact of EOR tax incentives are also considered. Each potential EOR project must be evaluated for its specific conditions. Rate of return and cost values cannot be directly applied to other EOR projects, but can be used as a guide to relative profitability.

(24928) Update of Industry Experience with CO_2 Injection
The main purpose of this paper is to utilize current industry experience to evaluate the performance to date of miscible CO_2 injection projects. Also included is a summary of innovations being implemented by industry to improve recovery from existing CO_2 projects. Experience to date has shown that on balance, CO_2 injection projects have performed better than anticipated and offer a significant opportunity for improving ultimate recovery from existing reserves.

(24644) Quantitative CO_2 Flood Monitoring, Denver Unit, Wasson (San Andres) Field
This paper presents a technique for monitoring CO_2 flood response and performance using wireline-derived petrophysical data. Results obtained with this technique are useful for quantifying CO_2 saturation, monitoring flood progress and vertical sweep, identifying potential out-of-zone injectant losses, and detection of non-responding layers.

The basis for identification of CO_2 is the gas effect on neutron log porosity. Using sonic porosity as an estimate of total porosity, gas (CO_2) is identified in zones where corrected neutron porosity is less than total porosity. Neutron porosity is obtained in flowing producers using a pulsed neutron log (TDTP). The porosity correction is empirical and was derived using data from a recent CO_2 pilot test.

Gas saturation data derived with this method are in agreement with independent estimates available from a CO_2 pilot project. Examples are given to show the application of the method in the Denver Unit. This method should be generally applicable to other ongoing Permian Basin CO_2 floods.

(24157) Overview of Production Engineering Aspects of Operating the Denver Unit CO_2 Flood

Shell Western E and P Inc. has been operating the Denver Unit CO_2 flood, the world's largest CO_2 enhanced oil recovery project, since 1983. The unit is in the Wasson Field in Gaines and Yoakum Counties in West Texas. While operating the flood, SWEPI has developed successful technology and operating methods for carbon dioxide flooding.

The paper is structured in three parts: 1) physical properties of CO_2, 2) physical effects of CO_2 and 3) relative economic considerations associated with CO_2. Operational considerations associated with each topic are identified and SWEPIs resulting modifications in operating policy are discussed. Some of the topics included in the paper are equipment and materials, artificial lift, well control, wellbore impairment, injection surveillance, and operations in a populated area. Discussions also include issues where our operating experience has varied significantly from our original expectations. These include the lower than expected corrosion rate of materials, and the higher than expected number of wells that flow naturally.

This overview will be of interest to companies who are either operating or preparing to implement CO_2 floods. It will also interest service companies who may have or wish to develop products to service CO_2 operations.

(24156) Production Performance of the Wasson Denver Unit CO_2 Flood

The Denver Unit, located in the Wasson Field of west Texas, is the world's largest Carbon Dioxide Enhanced Oil Recovery (EOR) project. Shell Western E and P Inc. initiated CO_2 injection in the Denver Unit in 1983, utilizing CO_2 from naturally occurring source fields in Colorado and New Mexico.

Production response to CO_2 flooding has been impressive, with over half of the current daily oil production attributable to CO_2 injection. In fact, oil production has substantially exceeded original project performance predictions.

The project was originally implemented with both a Continuous CO_2 injection area and a Water-Alternating-Gas (WAG) CO_2 injection area. A comparison of the performance of these two areas has clearly demonstrated the advantages of each injection method, and has led to the conversion of the Unit to a "Denver Unit WAG" (DUWAG) injection process, which plays on the strengths of both injection schemes.

This paper will cover in more detail the observed production performance of the CO_2 flood to date, present a comparison of the Continuous and Water-Alternating-Gas injection processes, and review the design and implementation of the Denver Unit WAG project. The paper will be of interest to companies who are either operating or preparing to implement CO_2 Floods.

(19783) An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs

In this paper we present the results of a technical and an economic evaluation of waterflood infill drillings in fourteen Clearfork and eleven San Andres carbonate reservoirs in West Texas. The initial waterflood recovery efficiency and the infill drilling waterflood recovery efficiency were estimated from decline curve analyses. The economic analysis was performed to evaluate the relative profitability of the waterflood infill drilling operations.

For Clearfork units, the estimated initial waterflood recovery efficiency ranged from 9.54 to 32.19% of original oil in place (N) with a medium of 17.75%N; and the infill drilling waterflood recovery efficiency ranged from 13.09 to 52.56%N with a medium of 25.53%N. The medium increase in oil recovery by infill drilling was 7.78%N. For San Andres units, the initial waterflood recovery efficiency ranged from 10.68 to 39.03%N with a medium of 19.97%N; and the infill drilling waterflood recovery efficiency ranged from 13.73 to 44.58%N with a medium of 31.82%N. The medium increase in oil recovery by infill drilling was 11.38%N.

A multi-linear regression analysis was used to establish regression models correlating the initial waterflood and the infill drilling waterflood recovery efficiencies to reservoir and process parameters. For the Clearfork units, the process parameters. For the Clearfork units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 20.39%N and 3.19%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 29.25%N and 2.48%N, respectively. The average increase in oil recovery by infill drilling was 8.86%N. For the San Andres units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 22.09%N and 1. 45%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 32.23%N and 2.73%N, respectively. The average increase in oil recovery by infill drilling was 10.14%N.

Two cases were studied in the economic analyses. Case I economic analysis used past and projected production schedule and economic projected production schedule and economic parameters. For the Clearfork units, the rate of parameters. For the Clearfork units, the rate of return ranged from 18.37% to 125.2% with a mean of 53.3%. The payout ranged from 1.22 years to 6.58 years with a mean of 3.14 years. For the San Andres units, the rate of return ranged from 20.58% to 500.0% with a mean of 157.0%. The payout ranged from 0.36 to 5.43 years with a mean payout ranged from 0.36 to 5.43 years with a mean of 1.77 years.

Case II economic analysis used past and projected production data as though the projects projected production data as though the projects were initiated in January 1988. The base crude oil price of $17.50/STB was assumed in the analyses. For the Clearfork units, the rate of return ranged from 11.41% to 98.80% with a mean of 40.4%. The payout ranged from 1.45 to 6.42 years with a mean of 3.53 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 4.28 years and 3.13 years using $22.50/STB. For the San Andres units, the rate of return ranged from 20.58% to 500.00% with a mean of 157.00%. The payout ranged from 2.36 to 4.91 years with a mean of 2.3 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 2.18 years and 2.00 years using $22.50/STB.

(19725) Analyzing the Flowing Performance of Oil Wells: Denver Unit CO_2 Flood

A mathematically precise method for determining the flowing life of oil wells is presented. Development of the necessary "outflow presented. Development of the necessary "outflow performance curves" and "flow charts" using performance curves" and "flow charts" using multiphase vertical flow calculations is explained and illustrated graphically. An example study of 377 wells in the Denver Unit CO_2 flood in the Wasson (San Andres) Field, Texas, is used to demonstrate this calculation procedure.

(19596) Outcrop/Subsurface Comparisons of Heterogeneity in the San Andres Formation

An integrated outcrop and subsurface study of permeability variations in the San Andres formation demonstrates the extreme heterogeneity present in this economically important carbonate horizon. Permeability measurements were made with a field permeameter and were Permeability measurements were made with a field permeameter and were compared to subsurface core data. Geostatistical techniques were used to predict variability and scales of spatial correlation. Measured permeability showed substantial variability within units arranged in permeability showed substantial variability within units arranged in three correlation scales. Outcrop permeability data exhibited no marked permeability anisotropy in predicted spatial correlation length. Several permeability anisotropy in predicted spatial correlation length. Several scales of spatial variability have been observed in an outcrop section, with subsurface results in agreement.

(18883) Equilibrium Acid Fracturing: A New Fracture Acidizing Technique for Carbonate Formations

The equilibrium-acid-fracturing technique was developed to stimulate wells in the Wasson San Andres Denver Production Unit. This new treatment technique maximizes acid contact time with the fracture faces while allowing control of the created fracture dimensions. Maximum acid contact time is essential to create highly conductive etched pathways on the fracture faces of cool dolomite formations that react slowly with acid. Control of fracture dimensions is important in the San Andres Denver Unit because fractures tend to grow uncontained in at least one vertical direction and the oil column is bounded by permeable gas-bearing intervals above and permeable water-bearing intervals below. With this technique, a fracture of desired dimensions is created by injection of acid at fracturing rates. The volume of acid required to create the desired fracture dimensions is determined by a 2D fracture-geometry program with design parameters determined from fracture field testing and laboratory testing. Injection is then continued at reduced rates that maintain equilibrium with the fluid leakoff rate from the created fracture faces. Maintaining equilibrium between injection and leakoff allows the created fracture to be held open without significant further fracture extension. Equilibrium is achieved in the field by maintaining the injection pressure below the fracture extension pressure but above the fracture closure pressure determined by fracture field testing. This paper presents the background and theory of this technique along with design procedures, field examples, results, and conclusions. Results of the equilibrium-acid-fracture treatments and other acid stimulations performed in the Denver Unit are also compared.

(17335) Comparison of Laboratory- and Field-Observed CO_2 Tertiary Injectivity
Although CO_2 injectivity should be significantly greater than brine injectivity because CO_2 has a much lower viscosity than brine, this behavior is not always seen, as shown in a Denver Unit field test. This paper examines features that cause differences in CO_2 injectivity with a model that uses simple non-dispersive flow with a series of constant-composition slugs to approximate the analytical solution (normally a sequence of shocks and tails) in a sequence of noncommunicating layers. Because of its simplicity, this model identifies the primary features that result in the different observed CO_2 injectivities more clearly than the finite-difference model. This paper shows that the qualitative differences between Cedar Creek anticline corefloods and field behavior result solely from differences in geometry. That is, a single set of centrifuge-measured, quasi-native-state, secondary-drainage relative permeabilities can be used to predict both laboratory and field behavior. Primary factors that contribute to the differences between the two field tests are fluid/rock properties, effective wellbore radius (or skin), and heterogeneity in the layering.

(16854) Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas
This paper presents the results of an economic analysis of infill drilling in 16 carbonate oil reservoirs located in West Texas. The economic analysis included the evaluation of incremental waterflooding recovery over primary and infill drilling recovery over initial waterflooding.

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Results from Case II studies showed that for a $15/STB ($94/m 3) oil price in 1986, about 68% of the infill drilling projects studied had an infill drilling incremental payout of less than two years with an incremental discounted cash flow rate of return greater than 20%. As the OOIP/WS increased, the general trend also showed an increasing infill drilling incremental net present value. When the oil price in 1986 was increased from $15/STB ($94/m 3) to) $25/STB 0157/m 3), the increase " the incremental net present value (INPV) was substantial. For example at a value of 20 for OOIP/WS (Means Field/San Andres), the INPV increased from $76 MM to $122 MM.

(14308) Investigation of Unexpectedly Low Field-Observed Fluid Mobilities during Some CO_2 Tertiary Floods

Phase behavior, inorganic precipitation, and wettability are investigated as possible reasons for the unexpectedly low field-observed mobilities during some CO_2 floods, in particular, the Denver Unit, Wasson field CO_2 pilot. The observed mobility was not a near-wellbore effect and probably played a major role in reservoir sweep: the low effective probably played a major role in reservoir sweep: the low effective permeability offset the detrimentally low CO_2 viscosity. Experimental and permeability offset the detrimentally low CO_2 viscosity. Experimental and simulation studies, supplemented by literature data, lead to the conclusion that rock wettability could be the root cause of these low fluid mobilities. Phase behavior effects, though they may play a role, are not necessary to explain the injectivity behavior, and inorganic precipitates probably have little effect under the conditions investigated here. Thus, probably have little effect under the conditions investigated here. Thus, current simulator modeling of low fluid mobilities, which are based on arbitrary permeability reduction factors allegedly caused by phase behavior, appears unjustifiable even though overall simulator results may be acceptable.

(13132) Effect of CO_2 Flooding on Dolomite Reservoir Rock, Denver Unit, Wasson (San Andres) Field, TX

This report documents results of a study to determine whether brine and carbon dioxide (CO_2) injection significantly changes total porosity in a dolomite reservoir. Pre- and postpilot cores from closely-spaced wells in the Shell Western E and P Inc. Denver Unit CO_2 pilot provided the necessary data. We concluded that only minor porosity enhancement resulted from brine dissolution of anhydrite.

(8406) Production Technology Experience in a Large Carbonate Waterflood, Denver Unit, Wasson San Andres Field

Shell Oil Co. currently is operating a large waterflood project in the Permian San Andres dolomite reservoir in west Texas. The project comprises Permian San Andres dolomite reservoir in west Texas. The project comprises 900 producers and 360 injectors. In addition to major infill drilling programs, a substantial remedial and reconditioning program has been programs, a substantial remedial and reconditioning program has been carried out. Highlights of production technology experience are presented.

(6385) Denver Unit 10-Acre Infill Pilot Test and Residual Oil Testing

A 10-acre infill pilot test was conducted in the Denver Unit of the Wasson San Andres Field of West Texas to determine if the Unit could be further infilled economically to a tighter spacing at the culmination of a 20-acre infill program. Primary objectives of the test were to (a) delineate pay discontinuity in this San Andres dolomite reservoir, (b) determine size, shape, and orientation of waterflood fronts, (c) determine oil productivity of potential 10-acre locations, and productivity of potential 10-acre locations, and (d) evaluate remaining oil saturation.

From the results of the three-well program, it was concluded that the pay program, it was concluded that the pay continuity is higher than had been interpreted from previous work. All productive zones within the pay interval are being flooded, although at different rates such that 10-acre locations do not appear to have sufficient economic potential to support further infilling. From test data, a preferential directional conductivity could not be ascertained. The results of several methods of investigating residual oil saturation (well bore logs, whole core analysis, laboratory core centrifuge, counter current imbibition tests, and laboratory waterflood susceptibility tests) are discussed.

TX-Wasson ODC (Click Wasson ODC to return to table)

(35402) Field Test of Foam to Reduce CO_2 Cycling

A foam treatment was conducted in the Wasson ODC Unit, Yoakum County, Texas, to significantly reduce CO_2 cycling through a high permeability zone between injection Well 324 and offset producing Well 455. Three thousand barrels of 0.5 wt% surfactant were injected. A novel placement technique was employed to place the surfactant primarily in the "thief" zone by utilizing crossflow within the wellbore caused by pressure differences between the tighter and more permeable pay zones.

Comparison of the injection and production rates before and after foam generation clearly indicated reduced CO_2 cycling between the wells. However, pre- and post-treatment injection profiles indicated that injectivity into all reservoir zones were affected by the foam. This suggested that crossflow within the wellbore was not sufficient in this case to keep surfactant out of the lower permeability layers. This test was run at the end of a water half-cycle. Post-treatment analysis of injection profiles run in Well 324 suggested that better placement of the surfactant may be achieved at the end of the CO_2 half-cycle.

The effectiveness of the foam gradually decreased with time, i.e., the injection rate slowly increased, due to drying out of the foam and movement of the surfactant bank away from the wellbore. The foam was twice regenerated by injecting a small slug of water to rehydrate the foam.

Overall the test was a technical success. However, this test was uneconomical due to the low cost of recycling CO_2 ($0.10/mcf). In order for foam to be economic at Wasson, better placement of the surfactant is needed so the processing rate in the tighter zones is not adversely affected, and a larger volume (or repeat treatments) is needed to affect areal sweep efficiency.

(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs

Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacings. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

(17754) A Brief History of the Wasson EOR Project

Amoco Production Co. and its partners embarked on a CO_2-based EOR project in 1982 at the Wasson ODC Unit (WODCU) Wasson, Field, Yoakum County, TX. Many years of studies and carefully coordinated planning preceded the projects approval. This paper reviews several aspects of the project and details the WODCU CO_2 removal plant.

(16830) CO_2 Injection and Production Field Facilities Design Evaluation and Considerations

Many technical papers have been published on CO_2 flooding from a reservoir standpoint; but, few have ever discussed design considerations of field CO_2 production and injection facilities. This paper will present initial design and installation considerations, design criteria, and initial installation problems associated with Amoco's four West Texas CO_2 projects (Slaughter Estate Unit, Central Mallet Unit, Frazier Unit, Wasson ODC Unit). Additionally, design and operational considerations, based on the experience gained from operating the four CO_2 floods during the last two years, will be discussed for use in future CO_2 facility designs.

Equipment problems which have been experienced during operation, modifications which have been made as a result of experience, and recommended changes for future designs will be discussed in this paper. Actual case histories of operations, equipment design, and equipment problems encountered will be presented. The specific areas to be discussed will include: The CO_2 injection system material selection and layout, CO_2 injection wellhead material selection and configuration, CO_2 injection well downhole equipment, producing wellhead pressure and material requirements, flowline and fluid gathering systems, satellite and central tank battery layout and operation, and the gas collection system layout and material selections.

Special considerations will be given to design details and material specifications that are often overlooked, or not considered. The resulting potential problems and failures of these oversights will be discussed.

TX-Wasson South (Click Wasson South to return to table)

(70063) South Wasson Clear Fork Reservoir Model: Outcrop to Subsurface via Rock-Fabric Method

South Wasson Clear Fork field produces from two reservoirs, the middle Clear Fork, with a seal located within the upper Clear Fork Formation, and the lower Clear Fork, with a seal located in the Tubb Formation. Six sequences have been defined on the basis of facies succession, seismic interpretation, and outcrop analog studies in Apache Canyon, Sierra Diablo Mountains, West Texas. Rock-fabric/petrophysical studies have shown that a single porosity-permeability transform and porosity-saturation-capillary- pressure model can be used to calculate permeability and water saturation in uncored wells. Five rock fabrics have been described, and all plot in the petrophysical class 1 field. This surprising result is related to the presence of large volumes of poikilotopic anhydrite, which reduces porosity but has little effect on pore size or permeability. Permeability values calculated from porosity logs are distributed in the interwell environment within a high-frequency-cycle (HFC) stratigraphic framework. Analog outcrop studies demonstrate that the Clear Fork Formation can be characterized by upward shallowing (HFCs). Identifying HFCs, however, is made difficult because of the high uranium content of the Clear Fork and the lack of a relationship between water saturation and rock fabric. A statistical relationship between porosity and rock fabric is developed, however, that allows porosity to be used as a surrogate for rock fabric, and vertical increases in porosity are interpreted as mud-dominated to grain-dominated fabric successions and used to define Huffs. The HFCs are divided into two rock-fabric flow layers, an upper, grain-dominated and a lower, mud-dominated layer, in order to preserve high- and low-permeability intervals. Permeability data from the outcrop analog in Apache Canyon are used to demonstrate that the vertical variability seen in the log calculations within the rock-fabric flow units does not represent permeable strata but is statistical variability at a near-random scale.

(24160) Early CO_2 Flood Experience at the South Wasson Clearfork Unit

This paper describes the implementation and performance of the industry's first Clearfork CO_2 flood - Shell's South Wasson Clearfork Unit (SWCU) located in the Permian Basin of West Texas. CO_2 injection began in 1986 using a high water-alternating-gas (WAG) ratio (8:1), low volume (8% hydrocarbon pore volume) flood, or "CO_2 augmented" waterflood. The intent of the flood was to increase our understanding of the Clearfork formation before committing to a larger scale CO_2 flood.

The performance of the "CO_2 augmented" waterflood has met expectations. After 3-1/2 years of CO_2 injection, enhanced oil production had increased to 450 BOPD, or 7 % of Unit production. CO_2 injectivity was comparable to water injectivity, and no significant decrease in the WAG water injectivity was observed. Encouraged by the success of the CO_2 augmented waterflood, a 2:1 WAG CO_2 flood was approved and implemented in the northern half of the CO_2 flood area in the spring of 1990.

Through 1991, roughly 3 % of a hydrocarbon pore volume of CO_2 has been injected at SWCU, and the cumulative enhanced oil recovery matches the original projections. The performance of the CO_2 flood to date has been influenced by reservoir heterogeneity, injection pattern modifications, waterflood operating practices, and gas processing constraints.

(19783) An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs

In this paper we present the results of a technical and an economic evaluation of waterflood infill drillings in fourteen Clearfork and eleven San Andres carbonate reservoirs in West Texas. The initial waterflood recovery efficiency and the infill drilling waterflood recovery efficiency were estimated from decline curve analyses. The economic analysis was performed to evaluate the relative profitability of the waterflood infill drilling operations.

For Clearfork units, the estimated initial waterflood recovery efficiency ranged from 9.54 to 32.19% of original oil in place (N) with a medium of 17.75%N; and the infill drilling waterflood recovery efficiency ranged from 13.09 to 52.56%N with a medium of 25.53%N. The medium increase in oil recovery by infill drilling was 7.78%N. For San Andres units, the initial waterflood recovery efficiency ranged from 10.68 to 39.03%N with a medium of 19.97%N; and the infill drilling waterflood recovery efficiency ranged from 13.73 to 44.58%N with a medium of 31.82%N. The medium increase in oil recovery by infill drilling was 11.38%N.

A multi-linear regression analysis was used to establish regression models correlating the initial waterflood and the infill drilling waterflood recovery efficiencies to reservoir and process parameters. For the Clearfork units, the process parameters. For the Clearfork units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 20.39%N and 3.19%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 29.25%N and 2.48%N, respectively. The average increase in oil recovery by infill drilling was 8.86%N. For the San Andres units, the mean and standard deviation for the best initial waterflood recovery efficiency correlation were 22.09%N and 1. 45%N, respectively. The mean and standard deviation for the best infill drilling recovery efficiency correlation were 32.23%N and 2.73%N, respectively. The average increase in oil recovery by infill drilling was 10.14%N.

Two cases were studied in the economic analyses. Case I economic analysis used past and projected production schedule and economic projected production schedule and economic parameters. For the Clearfork units, the rate of parameters. For the Clearfork units, the rate of return ranged from 18.37% to 125.2% with a mean of 53.3%. The payout ranged from 1.22 years to 6.58 years with a mean of 3.14 years. For the San Andres units, the rate of return ranged from 20.58% to 500.0% with a mean of 157.0%. The payout ranged from 0.36 to 5.43 years with a mean payout ranged from 0.36 to 5.43 years with a mean of 1.77 years.

Case II economic analysis used past and projected production data as though the projects projected production data as though the projects were initiated in January 1988. The base crude oil price of $17.50/STB was assumed in the analyses. For the Clearfork units, the rate of return ranged from 11.41% to 98.80% with a mean of 40.4%. The payout ranged from 1.45 to 6.42 years with a mean of 3.53 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 4.28 years and 3.13 years using $22.50/STB. For the San Andres units, the rate of return ranged from 20.58% to 500.00% with a mean of 157.00%. The payout ranged from 2.36 to 4.91 years with a mean of 2.3 years. A sensitivity analysis revealed that the average payout using $12.50/STB was 2.18 years and 2.00 years using $22.50/STB.

TX- Wasson Willard (Click Wasson Willard to return to table)

(27642) A Comparative Technical and Economic Analysis of Waterflood Infill Drilling and CO_2 Flood in West Texas Carbonate Reservoirs

Waterflood infill drilling and CO_2 flood have been used to improve oil recovery from West Texas Carbonate reservoirs. This paper presents a comparative study of technical and economic analysis of waterflood infill drilling and CO_2 flood in the Monahans (Clearfork) unit and Johnson J.L. 'AB' (Grayburg/San Andres) unit. Decline curve analysis is used to estimate the recovery efficiencies for different well spacings. An analogous study for West Texas reservoirs is used to estimate the CO_2 flood recovery. With waterflood infill drilling at 10-acre spacing, the recovery efficiency is estimated to improve to as high as 30% OOIP. However, economic analysis indicates that waterflood on a 10-acre well spacing is less profitable (ROR 8%) when compared to CO_2 flood (ROR 17%).

(24928) Update of Industry Experience with CO_2 Injection

The main purpose of this paper is to utilize current industry experience to evaluate the performance to date of miscible CO_2 injection projects. Also included is a summary of innovations being implemented by industry to improve recovery from existing CO_2 projects. Experience to date has shown that on balance, CO_2 injection projects have performed better than anticipated and offer a significant opportunity for improving ultimate recovery from existing reserves.

(19783) An Evaluation of Waterflood Infill Drilling in West Texas Clearfork and San Andres Carbonate Reservoirs

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(16854) Infill Drilling Economic Analysis of Carbonate Oil Reservoirs in West Texas

This paper presents the results of an economic analysis of infill drilling in 16 carbonate oil reservoirs located in West Texas. The economic analysis included the evaluation of incremental waterflooding recovery over primary and infill drilling recovery over initial waterflooding.

Because of limited field and economic data available for this study, many assumptions were made to complete the economic evaluations. Two major cases of economic evaluation were performed: Case 1 used the past production and economic data to 1986 and the projection of these data from 1986 on to the assumed economic limit, and Case II used the past infill production data as if the projects were initiated in January 1986 and on to the assumed economic limit.

Results showed that about 6811 of the infill drilling projects studied had an infill drilling incremental payout of less than two years with a incremental discounted cash flow rate of greater than 20%. Only 37% of the projects studied had a waterflood incremental economics with the same criteria. Decreasing the well spacing generally decreased the infill drilling incremental payout and increased the incremental cash flow rate of return. As the OOIP/WS (well spacing) increased, the general trend showed an increasing infill drilling incremental net present value.

Results from Case II studies showed that for a $15/STB ($94/m 3) oil price in 1986, about 68% of the infill drilling projects studied had an infill drilling incremental payout of less than two years with an incremental discounted cash flow rate of return greater than 20%. As the OOIP/WS increased, the general trend also showed an increasing infill drilling incremental net present value. When the oil price in 1986 was increased from $15/STB ($94/m 3) to) $25/STB 0157/m 3), the increase " the incremental net present value (INPV) was substantial. For example at a value of 20 for OOIP/WS (Means Field/San Andres), the INPV increased from $76 MM to $122 MM.

(15037) An Economic Evaluation of Waterflood Infill Drilling in Nine Texas Waterflood Units
This paper examines the profitability of past waterflood infill drilling programs. The past waterflood infill drilling programs. The project data is from the Texas Railroad project data is from the Texas Railroad Commission files, and includes large carbonate and sandstone reservoirs such as the Wasson (San Andres) Field and the Big Wells (San Miguel) Field. All of the reservoirs were subject of intensive reservoir engineering and geologic study by the oil companies prior to initiation of the infill drilling project. The permeability of the reservoirs averages 8.8 md and ranges permeability of the reservoirs averages 8.8 md and ranges from .65 md to 27 md. The porosity averages 10% and ranges from 7% to 18.6%. The depths range from 1220 to 1525 meters with the deepest at 2130 meters.

Because of the large capital cost required for drilling and operating additional wells, it was not clear whether the infill drilling programs had recovered enough additional oil to be programs had recovered enough additional oil to be good investments. In spite of the variability of external factors such as the cost of wells and price of oil, all of the projects studied obtained at least an acceptable economic return. the average discounted profit to investment ratio was 2.0, and the average incremental oil per well was 15 thousand cubic meters. Most of per well was 15 thousand cubic meters. Most of the calculated rates of return exceeded 30%. The net present value at 15% after taxes ranged from $580,000 to $32 million dollars. Thus these waterflood infill drilling projects have generally been very successful.

(7051) A Method for Projecting Full-Scale Performance of CO_2 Flooding in the Willard Unit
A non-producing CO_2 flood tertiary recovery test was recently completed in the Willard Unit of Wasson Field. Flood responses during waterflood and alternate injection of CO_2 and water were monitored at a logging observation well using compensated neutron and pulsed neutron logs. A pressure core was taken to measure residual oil saturations at the test conclusion.

The overall objective of the testing was to obtain information for evaluating the potential for full-scale CO_2 flooding in the unit. Our method for making this evaluation involves: (1) defining CO_2 flood displacement efficiency and representing this efficiency in a miscible flood reservoir simulator; (2) defining a representative average reservoir description; and (3) projecting full-scale CO_2 flood performance with the simulator. The paper provides a performance with the simulator. The paper provides a status report on progress to assess CO_2 flooding potential for the Willard Unit in this manner. potential for the Willard Unit in this manner

(7050) Coring for In-Situ Saturations in the Willard Unit CO_2 Flood Mini-Test
From Aug. 1972 until May 1976, Atlantic Richfield tested CO_2 miscible flooding for tertiary recovery in the stratified San Andres dolomite of the Willard Unit, Wasson field. After first water-flooding the test area, CO_2 and water were injected in small, alternate slugs. This was followed by continuous water injection. During all phases of the test, flood response was monitored at a logging observation well, and at the conclusion of flooding, a core was taken between the injection and observation wells with the pressure-retaining core barrel.

This paper describes our attempt to measure in-situ saturations by pressure coring. Residual oil and CO_2 saturations were measured in the CO_2-flooded strata, and waterflood residual oil saturations were measured for the strata not swept by CO_2. Gas compositions were determined for all zones and were used to positively identify the CO_2 invaded strata. The paper contains a discussion of how the cores were taken and analyzed and a discussion of the data and its significance for CO_2 flooding.

(7049) Use of Time-Lapse Logging Techniques in Evaluating the Willard Unit CO_2 Flood Mini-Test
This paper describes how compensated neutron and pulsed neutron logs were used to monitor performance pulsed neutron logs were used to monitor performance of a tertiary recovery minitest of CO_2 miscible

flooding. The paper contains (1) a description of procedures used to take and interpret the logs, procedures used to take and interpret the logs, (2) a discussion of the significance of the log responses, and (3) a discussion of the accuracy of calculated saturation changes.

The experiment was run in the San Andres dolomite formation in the Willard Unit, Wasson field. Logs were taken in an observation well, completed with unperforated steel casing, and located 100 ft from the CO_2 injector. Water was injected first to thoroughly waterflood the region near the observation well. This was followed by injection of CO_2 and water in small, alternate slugs. Logs were taken regularly during both the waterflood and the CO_2 flood.

(6389) Case History: A Pressure Core Hole
A core hole was needed in the Willard Unit, Wasson Field, CO_2 Pilot Test in order to evaluate the effectiveness of CO_2 flooding. The coring program was designed to determine the residual oil saturation behind the CO_2 front and the waterflood residual oil saturation in zones not yet affected by CO_2. For the most definitive interpretation of the oil saturations found in the core, the presence of CO_2 needed to be associated with the lowest oil saturations. Saturation measurements on conventional cores may result in incorrect values for one or both of two primary reasons: (1) some hydrocarbon may be stripped from the coring by mud filtrate invasion, (2) and additional fluids may be driven from the core by gas expansion as the pressure is reduced during surfacing. If flushing by mud filtrate is controlled then valid fluid saturations can be obtained using a pressure retaining core barrel to prevent loss of fluids by gas expansion. Furthermore, if gas saturation and/or composition is desirable, then pressure coring is necessary and this was the situation at Willard. However, a major disadvantage to pressure coring is its high cost and a rather low 60% historical success ratio of getting core to surface under pressure.

This paper summarizes the work done with the pressure core barrels prior to spudding in order to increase our chances of getting core to surface under pressure. It also outlines the field procedures which were followed that resulted in obtaining 18 pressure cores out of 19 attempts. Also, discussed in this paper are the core analysis techniques which were used to determine oil, water, and gas saturations at reservoir conditions for full diameter cores.

(6388) A Review of the Willard (San Andres) Unit CO_2 Injection Project
The Willard Unit is located in the Wasson (San Andres) Field in Yoakum County, Texas. The reservoir is a layered dolomite with an average porosity of 8.5 percent and average permeability porosity of 8.5 percent and average permeability of 1.5 md. Secondary recovery by waterflooding has been in progress since 1965. Although secondary operations have been quite successful in the Willard Unit, a substantial amount of oil will be unrecoverable by waterflooding. CO_2 miscible displacement project was conducted in the unit to investigate the applicability of this process for full scale improved oil recovery.

The project consisted of two separate field tests to study the various operational and reservoir aspects of the CO_2 miscible process. The first of these consisted of eight adjacent CO_2 injection wells on regular waterflood spacing. Since this was the first effort to conduct a CO_2 miscible flood in this unit, this test was called Phase I. Water and CO_2 were injected alternately Phase I. Water and CO_2 were injected alternately in Phase I from November, 1972, to February 1975. This area was planned to provide insight into the extent of reservoir sweep problems that might occur in a regular size pattern CO_2 flood. It would also provide an opportunity to investigate control measures if these problems arose. Additionally, information would be obtained on injection performance and operational procedures that could be used in planning a unit-wide flood. The second test was located and operated separately from Phase I and was called the Pilot. It consisted of four wells: an injector, logging observation well, pressure observation and sampling well, and pressure core well, all on close spacing. The Pilot was designed to allow a more detailed investigation of the reservoir flow behavior of CO_2 and water and to determine the reduction in waterflood residual oil levels due to CO_2 injection.

Phase I injection performance was good. The reservoir pressure was maintained above the minimum required for miscible displacement. Cumulative CO_2 injection was 3.8 BCF of CO_2, or 4.4% of the hydrocarbon pore volume.

TX-Welch (Click Welch to return to table)

(62588) Interwell Seismic for Reservoir Characterization and Monitoring

The U.S. Department of Energy Class II Oil Program was designed to encourage evaluation of new technologies which might improve production in marginal shallow-shelf carbonate reservoirs. One of the largest of the approved programs has been underway in the Welch field, located in the Permian Basin of west Texas for several years. In the first phase of the program, a wide variety of data was acquired, including 3-D seismic, log and core data, and one of the largest interwell seismic baseline programs to be carried out at that time. The purpose of the interwell seismic program was twofold. First, there was interest in using the baseline survey data itself to evaluate its use for reservoir description and characterization (simulation). The second objective was to acquire subsequent monitor surveys, after CO_2 injection had begun, in order to map the actual location and movement of the CO_2 through the reservoir, as the program progressed.

The first phase of the project is now complete, and the first round of monitor surveys has been acquired in the second phase of the program. Based on comparison of the baseline surveys and the first monitor surveys, and using prior petrophysical work as a basis for interpretation of the results, the injected CO_2 appears to be exhibiting a strongly preferential flow direction oriented toward the east/southeast.

(39808) West Welch CO Flood Simulation with an Equation of State and Mixed Wettability

This paper describes the reservoir engineering aspects of the CO feasibility study for Department of Energy Class II project, at the West Welch San Anders Unit. The DOE Class II demonstration simulation effort for the CO feasibility study uses an 11 component equation of state (EOS) for surface facility design. Relative permeability data measured in the laboratory indicated two different waterflood residual oil saturations. The low reservoir temperature causes the fluid phase behavior to exhibit a two liquid hydrocarbon phase region with CO present Fluid characterization steps taken to virtually eliminate the two liquid hydrocarbon phase region is described. The problems these changes created and adjustments made to the EOS to improve the simulation are reviewed. We show that the EOS needs to predict slim tube recovery compositions as well as the total slim tube recovery to adequately predict field scale oil recovery. The fluid characterization procedure, described here, made the full field simulations more closely match field CO recovery.

Two types of wettability were identified from relative permeability curves at the project in the Welch field. The intervals of different wettability were identified from resistivity logs to aid in placing these intervals in the proper model layers. The geologic model with both relative permeability rock types led to overpredicting oil recovery. However, the low waterflood residual oil saturation appears more significant in the higher permeability rock. Thus, the relative permeability tests from core samples with higher permeability led to significant differences in model results. Subsequent history matching efforts, incorporating 3D seismic, showed that the relative permeability rock type with low residual oil saturation to water was not volumetrically significant. A separate paper, SPE 39809, describes the incorporation of 3D seismic into the geologic model.

(35160) Characterization of Rock Types With Mixed Wettability Using Log and Core Data - DOE Project Welch Field, Dawson County, Texas

In conjunction with the DOE Project (DE-FC22-93BC14990), the characterization of a portion of the Permian age San Andres formation under Welch Field, Dawson County, Texas was initiated. The objective of the characterization is the construction of a geologic model for the numerical simulation of a CO_2 flood of the reservoir. A detailed reservoir description is required because the high costs to inject and recycle CO_2 dictate a very efficient flood design. Identification of reservoir barriers, flow units, and prediction of continuity present the greatest challenge to the description. The productive portion of the formation is mineralogically simple, consisting of dolomite and anhydrite with very minor amounts of chert and illitic clay. Deposition occurred in a very flat shallow shelf setting ranging from supra tidal to subtidal. Depositional textures are variable ranging from fenestral mudstones to oolitic grainstones, with wackestones and packstones dominating. Diagenesis of these shallow shelf deposits has created a highly complex pore system which at times crosses depositional facies boundaries. Rock fluid interaction further complicated the descriptive process by affecting the log responses.

Porosity-permeability cross plots exhibited good correlation for a carbonate reservoir but were too coarse for simulation purposes. Special core analysis tests of capillary pressure and relative permeability provided the key for identifying the intervals of differing wettability and pore structure. A methodology has been developed to identity the varying pore, systems and differing wettabilities, using multiple logs from a routine logging suite and special core analysis. The input from multiple log measurements provides a better estimation of the formation absolute permeability than by using a single porosity-permeability relation. These reservoir parameters could then be extrapolated to uncored wells, using the sequence stratigraphy framework, to build the 3-D model of the reservoir.

(27676) CO_2 Operating Plan, South Welch Unit, Dawson County, Texas

The South Welch Unit of the Welch Field commenced full scale injection of CO_2 beginning in September of 1993. The flood design was based on the performance of a 180 acre pilot conducted from 1982 to 1987. A compositional model study of the pilot performance was used to design a CO_2 processing facility and the full scale flood operating approach. Primary, secondary and tertiary performance matching were used to verify the reservoir and process description and to forecast performance under a full field scenario. Scaleup was based on floodable pay from the modeled area related to the remaining areas under consideration for flood.

Reservoir simulation and economic analysis were used to investigate water alternating gas (WAG) cycle lengths, WAG ratio, and total slug sizes. Phasing of areas was coupled to level plant loading considerations, water handling limits, and short term profitability to develop an operating plan for the Unit.

(12664) CO_2 Miscible Flooding Evaluation of the South Welch Unit, Welch San Andres Field

The South Welch Unit, in Dawson County, Texas, was selected as a miscible flooding candidate in 1981 based on the recommendation of a feasibility study. The central 300 acres (1,214 Mm) of the unit were designated as the Phase One area, and infill drilling of this area was begun in 1981. CO 9 injection was initiated in February of 1982 with CO_2, trucked to the location in liquid form. Simulations were made to predict the recovery from the Phase One area under predict the recovery from the Phase One area under several production methods. These methods included:

20% IHCPV slug CO_2 injected continuously 20% IHCPV slug CO_2 injected using a 2:1 4 cycle WAG
25% IHCPV slug CO_2 injected using a 2:1 3 cycle WAG
Continued waterflooding on 20 acre line drive patterns

All simulations were made with the current CO_2 supply limitations taken into consideration. The 25% slug, 2:1 5 cycle WAG case is the optimum mode of operation based on sensitivity studies.

(39) History of the Welch Field San Andres Pilot Water Flood

A successful San Andres water flood pilot has been in operation in the Welch field for five years. Because of the unusual amount of data available, it should be possible to use its performance to test water flood predictions. One method of prediction is suggested and results are compared with actual performance. Data are given on the dilution of injected water by connate water. Since many other San Andres floods are being proposed, this paper should be useful to engineers who will be concerned with predicting their performance.

TX-Wellman (Click Wellman to return to table)

(48948) Wellman Unit CO_2 Flood: Reservoir Pressure Reduction and Flooding the Water/Oil

CO_2 injection is a proven technology. Results from two decades of reservoir and economic performance prove that CO_2 can 1) be transported over large distances via pipeline 2) handled and injected easily at well-site facilities and 3) recover oil that water injection could not mobilize. This has been accomplished at cost levels which are profitable provided enough HCPV (hydrocarbon pore volume) of CO_2 is injected in the reservoir and sweep and displacement efficiency are sufficient.

The most recent challenge involves optimizing efficiency of CO_2 flooding, i.e. maximizing oil recovery while at the same time reducing operating expenses. A useful method to attain the goal of CO_2 flood optimization is careful performance review of better performing CO_2 floods. The Wellman Unit CO_2 flood has a long history. This CO_2 flood is one of the most successful CO_2 floods documented in terms of CO_2 utilization, i.e. MCF of CO_2 required to recover one barrel of oil. This paper explores the role of laboratory experimentation for improvement of performance of a mature CO_2 flood.

In this paper, we will review the history of the Wellman Unit CO_2 flood and examine two possibilities to optimize reservoir performance: 1) Reducing CO_2 injection pressure thereby reducing the volume of purchased CO_2 while at the same time maintaining miscibility (optimum displacement efficiency) and 2) Exploring the possibility of mobilizing reserves in the water-oil transition zone below the original oil-water contact.

(22898) Reservoir Performance of a Gravity-Stable Vertical CO_2 Miscible Flood: Wolfcamp Reef Reservoir, Wellman Unit

A CO_2 miscible flood was implemented in the Wellman Unit Wolfcamp reef reservoir in 1983. CO_2 is being injected into the crest of the reservoir to displace the oil vertically downward. Water is being injected in the lower water-swept region of the reservoir to maintain reservoir pressure slightly above the minimum miscibility pressure.

This paper reviews the operating strategy and performance of the gravity-stable CO_2 miscible flood. The performance to date has been encouraging and indicates excellent volumetric conformance and ultimate recovery.

(11129) Numerical Simulation of a Gravity Stable, Miscible CO_2 Injection Project in a West Texas Carbonate Reef

Performance predictions of a proposed miscible CO_2 injection project for the Wellman Field, Terry County, Texas were made using an enhanced oil recovery process numerical simulator. The study investigated the potential of injecting a relatively small, gravity stable CO_2 slug with nitrogen as the drive gas into the crest of the cone-shaped reservoir. The effects of slug size, injection rate and reservoir pressure were evaluated for an optimum future operating plan.

The differences in fluid densities at reservoir conditions were conducive to gravity segregation of the nitrogen, CO_2 and miscible oil bank. Assuming that most of the produced CO_2 would be reinjected, a CO_2 slug as small as 15 % of the initial hydrocarbon pore volume appeared to be sufficient to mobilize the remaining recoverable oil in-place. Oil production performance during the early years of the project was similar production performance during the early years of the project was similar for CO_2 injection rates of 10 MMSCF/D and 20 MMSCF/D so the lower rate case appeared economically more attractive. Since the massive carbonate reef, having a vertical oil column of over 800 feet, exhibited no major barriers to impede horizontal or vertical fluid flow, an excellent sweep of the reservoir was predicted in all cases.

The shape and integrity of the thin CO_2 slug depended to a great extent on the location of the producing wells and the magnitude of their drawdowns. The successful implementation of the proposed CO_2 flood in the field will require a continuous pressure and production monitoring system with an ongoing workover and recompletion program to stay ahead of the gas front.

The results of this study indicated that the concept of the proposed CO_2 flood was reasonable and could provide an economic tertiary oil recovery process for the Wellman Field.

Though most Middle East oil reservoirs have remaining many years of primary and secondary recovery the potential benefits of tertiary recovery primary and secondary recovery the potential benefits of tertiary recovery methods should be investigated thoroughly before future action is necessary. A miscible CO_2 injection scheme similar to the one studied for the Wellman Field may be applicable to some of the reservoirs in that area if the proper conditions exist.

(10065) A Technique for Obtaining In-Situ Saturations of Underpressured Reservoirs

Pressure coring offers a method for obtaining in-situ Pressure coring offers a method for obtaining in-situ reservoir saturations. However, because of the requirement of pressure balance during coring, it so far has been limited to use in reservoirs with pressure gradients greater than 0.25 psi/ft (5.7 kPa/m). This paper describes techniques used to obtain the first known successful pressure cores taken using a foam mud system, thereby extending the useful range of pressure coring to underpressured reservoirs. Stable foam is a compressible non-Newtonian fluid that requires special design considerations when used in conjunction with pressure coring. Careful well design is necessary to ensure that bottomhole pressure (BHP) during drilling and coring operations does not fall below reservoir pressure. This can occur easily if foam degradation and nonlinear pressure gradients are not considered. A complete pressure gradients are not considered. A complete technique for using foam to pressure core, including well design, field implementation, and core handling, is presented in this paper. This technique includes a presented in this paper. This technique includes a wellbore design, a pressure analysis method, a method of selecting optimal foam design, a description of logistics, an empirical calibration test, and a description of pressure coring operations and core handling.

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(39809) Improving Flow Simulation Performance with a Seismic-Enhanced Geologic Model

The DOE Class 2 Demonstration Project operated by OXY USA Inc. in the West Welch Unit was designed to enhance economics in IOR projects in lower quality shallow shelf carbonate reservoirs. Accurate reservoir description is critical to the effective evaluation and efficient design of IOR projects in heterogeneous reservoirs. Therefore, the majority of the pre-injection effort was devoted to developing a geologic model that would allow a flow simulator to accurately match and predict reservoir performance. A base geologic model was constructed utilizing standard correlation and extrapolation methods to distribute the wellbore data across the interwell area. With the base geologic model, the flow simulator could only obtain a history match by making changes in porosity, net pay, and permeability of grid cells in the model. The changes were made using conventional history matching techniques, and the revised geologic model may not have been representative of the formation although a history match was obtained.

The base geologic model was then enhanced by incorporating seismic-guided porosity and pore volume map data to define the interwell properties. Since the seismic traces were on approximately the same spacing as the model grids, reservoir properties of porosity and thickness were available at each grid block. With the enhanced geologic model, the simulator was able to match the historical total fluid rates without the use of porosity or permeability multipliers. The simulator's water/oil ratio was too low with this model. Net pay and pay continuity were identified by other methods as the controlling parameters in the waterflood history match. The revisions resulted in higher oil saturation at the start of CO flood and an increase in forecasted oil production during tertiary recovery than when not using the seismic data. The predicted injection for the first three months is matching the actual field rates indicating these were valid changes to the simulator.

(39808) West Welch CO Flood Simulation with an Equation of State and Mixed Wettability

This paper describes the reservoir engineering aspects of the CO feasibility study for Department of Energy Class II project, at the West Welch San Anders Unit. The DOE Class II demonstration simulation effort for the CO feasibility study uses an 11 component equation of state (EOS) for surface facility design. Relative permeability data measured in the laboratory indicated two different waterflood residual oil saturations. The low reservoir temperature causes the fluid phase behavior to exhibit a two liquid hydrocarbon phase region with CO present Fluid characterization steps taken to virtually eliminate the two liquid hydrocarbon phase region is described. The problems these changes created and adjustments made to the EOS to improve the simulation are reviewed. We show that the EOS needs to predict slim tube recovery compositions as well as the total slim tube recovery to adequately predict field scale oil recovery. The fluid characterization procedure, described here, made the full field simulations more closely match field CO recovery.

Two types of wettability were identified from relative permeability curves at the project in the Welch field. The intervals of different wettability were identified from resistivity logs to aid in placing these intervals in the proper model layers. The geologic model with both relative permeability rock types led to overpredicting oil recovery. However, the low waterflood residual oil saturation appears more significant in the higher permeability rock. Thus, the relative permeability tests from core samples with higher permeability led to significant differences in model results. Subsequent history matching efforts, incorporating 3D seismic, showed that the relative permeability rock type with low residual oil saturation to water was not volumetrically significant. A separate paper, SPE 39809, describes the incorporation of 3D seismic into the geologic model.

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