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Improved Efficiency of Miscible CO₂ Floods and Enhanced Prospects for
CO₂ Flooding Heterogeneous Reservoirs

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ABSTRACT

The goal of this project is to improve the efficiency of miscible CO₂ floods and enhance the prospects for flooding heterogeneous reservoirs. This report provides results of the second year of the three-year project that will be exploring three principle areas:

- Fluid and matrix interactions (understanding the problems).
- Conformance control/sweep efficiency (solving the problems).
- Reservoir simulation for improved oil recovery (predicting results).

During this past year tests were completed that demonstrate the feasibility of using lignosulfonate as a sacrificial agent in CO₂-foam flooding. Foam durability tests demonstrated the optimum concentration for lignosulfonate with a primary foaming agent. Flooding experiments conducted in a composite core containing high and low permeability regions demonstrated that mobility was reduced and the oil recovery increased. Adsorption experiments indicated the benefits of using a primary foaming agent with lignosulfonate to improve economics.

A number of techniques developed over the years at PPRC as well as conventional tests were used to assess the feasibility of a water and/or CO₂ flood of the low permeability Blinberry reservoir in the Teague field. Recovered core from one well and well logs from across the field were evaluated and with laboratory tests were used to reevaluate the original oil in place, oil distribution, and prospects for fluid injection to increase oil recovery significantly.

A preliminary study using a fuzzy controller for parameter adjustments in history matching indicate satisfactory results can be obtained. A promising approach for implementing fully automatic history matching is proposed. A software tool is presented that utilizes parallel and distributed simulation across the Internet for configuring a web-based parallel processing system to support a soft computing technique for reservoir simulations. This technique solves history matching, economically using commodity hardware or a cluster of ordinary PCs.

A technique is presented for using neural networks as an aid for solving nonlinear engineering problems that are encountered in optimizing simulations and modeling, and complex engineering calculations. For many large-scale engineering problems, finding good starting points for the iterative algorithms is the key to good performance. Neural networks are used to select starting points for the iterative algorithms for nonlinear systems. The method is illustrated using four small nonlinear equation groups. Two real applications in petroleum engineering are also given to demonstrate the method's potential application in engineering.

A literature review was completed on CO₂ projects to identify the extent of injectivity problems, especially related to alternating the injection of water with gas. This review covers specific characteristics, and correlates the hypothesis and theories of the causes and expectations of injectivity behavior in various CO₂ and gas flooded reservoirs. The intent of the paper is to:

- provide a concise compendium to the current understanding of the WAG mechanism and predictability,
- provide a comprehensive single source review of the causes and conditions of injectivity abnormalities in CO₂/gasflood EOR projects,
- aid in formulating the direction of research, and
- help operators develop operational and design strategies for current and future projects as well as input parameters for simulating current and future projects.

EXECUTIVE SUMMARY

Advances in a number of areas have been achieved during this past year. Five specific areas are presented in this Annual Report:

1. Encouraging results have been obtained that will be used in developing cost-effective cosurfactant and sacrificial agent systems for CO₂ foam systems. Lignosulfonates both reduce the amount of primary foaming agent required to satisfy reservoir rock adsorption and the concentration of primary foaming agent required to reduce system mobility.
2. A study demonstrates cost-effective techniques to aid in the determination of the feasibility of fluid injection—water and/or CO₂—in a Permian Basin low-permeability reservoir. In the example, present plans for this reservoir will produce only about 10% of the original oil in place. This type of study can be used to assess small- to medium-sized reservoirs.
3. A study demonstrates the prospects of using fuzzy logic and parallel processing to improve history matching and greatly reduce the cost of computational time. The use of fuzzy logic should greatly reduce cost and time to develop accurate production history matches. This is done using parallel processing of a cluster of PCs that can be tailored to company size.
4. Neural networks are used to solve nonlinear engineering problems specifically related to petroleum engineering. Some sample problems are presented.
5. A literature review of injectivity issues related to the alternating injection of water and CO₂ has been completed and is presented. The purpose is to provide a concise compendium of the current understanding of the WAG mechanisms, a comprehensive, single-source review of the causes and conditions of injectivity abnormalities in CO₂/gas flood EOR projects, to aid in formulating the direction of research, and to help operators improve and design strategies for current and future projects.

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BACKGROUND

The use of CO₂ as an injection fluid for oil recovery was initiated by the 1950s.^{1, 2} Today CO₂ flooding is considered one of the most promising techniques for improving oil recovery from oil reservoirs.³⁻⁷ A number of research groups have studied mechanisms affecting performance of CO₂ injection, including phase behavior,⁸⁻¹⁹ compositional effects,²⁰⁻²⁴ and IFT.²⁴⁻³² However, it is unclear what constitutes the "optimum design" of CO₂ flooding. Thomas et al.⁶ recently summarized the current situation of CO₂ miscible flooding as: "Depending upon where in the world one is implementing gas injection and to whom one is speaking, the post-mortem evaluations of 'miscible flooding' may vary from being very successful to 'miserable flooding'."

However, CO₂ injection has almost universally been a technical success. Now in the 90s, CO₂ injection in the U.S. is profitable in over 80% of the reported projects.^{33,34} One reason that some CO₂ floods have underperformed is believed to be the lack of understanding of the mechanisms of CO₂-oil-rock interaction under flow conditions in oil reservoirs. Although CO₂ flooding has been studied for over forty years, most research has been focused on the effect of CO₂-oil phase behavior on oil recovery. It appears that there is a lack of understanding of the extent and the effect of heterogeneity in most oil reservoirs during the design of the CO₂ project. Therefore, it is unclear as to what constitutes the "optimum design" of CO₂ projects. This project is an investigation of how to effectively link theoretical and experimental aspects of heterogeneity to the performance of CO₂ floods.

Because of the importance of CO₂ flooding to future oil recovery in New Mexico and west Texas, the Petroleum Recovery Research Center (PRRC) maintains a vigorous experimental program in this area of research. The Department of Energy (DOE), the State of New Mexico, and a consortium of oil companies support this research.

This report summarizes work done during the second year of the second three-year project entitled "Improved Efficiency of Miscible CO₂ Floods and Enhanced Pros-

pects for CO₂ Flooding Heterogeneous Reservoirs," adding to the information obtained during the first year.³⁵ The first three-year project³⁶⁻³⁸ was based on encouraging results obtained from a previous laboratory project entitled "Improvement of CO₂ Flood Performance,"³⁹ and a DOE-awarded grant for a CO₂-foam field demonstration that was a successful forerunner of DOE's Class I, II, and III Field Demonstration projects. This project was entitled "Field Verification of CO₂-Foam."⁴⁰

Our studies in selective mobility reduction (SMR) have progressed well. Selective mobility reduction is the property of CO₂-foam whereby mobility is reduced by a greater fraction in higher than in lower permeability zones. It is also a property that promises to improve displacement efficiency in CO₂ floods by reducing the effects of reservoir heterogeneity. The experimental studies related to foam have shifted toward reducing the cost of application by identifying agents that can reduce the cost of chemicals.

CO₂-foam coreflood tests continue and are being used to identify and quantify a number of variables in foam flooding; effects of flow rate, gas foam quality (gas volume fraction), and surfactant concentration. Foam and horizontal well models were developed, refined, and tested to verify the feature. The programming and testing of two reservoir simulators (MASTER—Miscible Applied Simulation Techniques for Energy Recovery—from the Department of Energy, and UTCOMP, provided by the University of Texas at Austin) and testing on a reservoir scale for the foam option were completed.

Multiphase flow behavior in fractured reservoirs is being investigated. Understanding the relationship of fluid flow and reservoir heterogeneity in fractured reservoirs is the key factor in developing a strategy of improving oil recovery in these reservoirs. A pendant drop apparatus for measuring IFT at reservoir conditions has been designed, built, modified, and tested. A new method, based on a static force balance on the lower half of the pendant drop used to calculate low IFT, has been developed and shown to work at low IFT.

Finally, we have been aggressive in publication and dissemination of the results of our research. This has included quarterly reports and a number of related publications during the first year^{34,41-47} and second year⁴⁸⁻⁵⁰ of this project. Also, several papers have

been accepted for presentation and publication in upcoming international meetings. In addition, we organized the third CO₂-Oil Recovery Forum, held October 28, 1998. The two-day forum had about 90 participants, representing 39 organizations. This was the third year in a row that we have hosted this very successful forum.

We are pleased with the progress we have made. Even with the relatively low oil prices in recent years, most CO₂ field projects are considered economic successes,^{33,34,51} with current projects and engineering for future projects commencing each year in the west Texas—New Mexico area. In fact, CO₂ suppliers are drilling new CO₂ production wells, to increase available CO₂ for delivery, and plans are under way to increase current pipeline capacities. Also, other areas in North America, such as the Wyoming-to-Canada corridor and the Mississippi region, continue to consider extending the current pipeline networks to encompass wider areas. In the United States, CO₂ injection is the only significant improved oil recovery method that has resulted in increased yearly oil production, despite fourteen years of depressed oil prices.⁵¹ CO₂ is a proven means of improving oil recovery and must be exploited to the fullest extent to increase national and individual company recoverable reserves.

There are many reservoirs that are not being considered for CO₂ or any type of improved oil recovery because of low fracture pressure, poor injectivity, extreme heterogeneity, or fractures. In some CO₂ floods, sections are often shut in early because of gas channeling. It is more crucial than ever, that research organizations interact with operators concerning IOR techniques such as CO₂ injection to maximize domestic resources. Thus, the developments from our present project and the proposed extension of our project are an asset to the economic and strategic future of the United States of America.

PROGRAM OBJECTIVE AND STATEMENT OF WORK

The present project consists of an experimental research effort aimed at improving the effectiveness of CO₂ flooding in heterogeneous reservoirs. The intent is to investigate new concepts that can be applied by field operators within the next two to five years. The proposed activities will consist of experimental research in three closely related areas:

1. Fluid and matrix interactions (understanding the problems): interfacial tension (IFT), phase behavior, development of miscibility, capillary number (Nc), wettability, gravity drainage, etc.
2. Conformance control/sweep efficiency (solving the problems): reduction of mobility using foam, diversion by selective mobility reduction (SMR) using foam, improved injectivity, WAG, horizontal wells, etc.
3. Reservoir simulation for improved oil recovery (predicting results): gravity drainage, SMR, CO₂-foam flooding, IFT, injectivity profile, horizontal wells, and naturally fractured reservoirs.

SECTION 1

CONFORMANCE CONTROL/SWEEP EFFICIENCY

The addition of surfactant in brine during a water alternating with CO₂ (WAG) injection or coinjection with CO₂ process has proven to produce foams that reduce CO₂ mobility. Our latest experimental results demonstrated that foam is useful in correcting non-uniform frontal displacement due to the heterogeneity of a reservoir formation. For foam to propagate through a reservoir at a satisfactory rate, mitigation of the loss of foaming agent by adsorption is a critical factor. As a practical approach for reducing the loss of costly surfactants and ensuring a satisfactory foam displacement, the use of sacrificial agents is evaluated in our laboratory during this past year.

Several tests were designed to investigate the feasibility of using lignosulfonate as a sacrificial agent in CO₂-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 CO₂ to correct the nonuniform flow pattern in a heterogeneous porous media. In composite core sample experiments, foams were effective in diverting CO₂ 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 CO₂-foam flooding process.

INTRODUCTION

Surfactant-based mobility control in CO₂ flooding is an effective way to mitigate problems normally associated with the miscible gas recovery processes. In laboratory results,⁵²⁻⁵⁷ the addition of surfactant in brine during a water alternating with CO₂ (WAG) injection or coinjection with CO₂ process produced foams that reduce CO₂ mobility and increase the displacement efficiency. Recent field tests also demonstrated the potential of CO₂-foam for mobility control or fluid diversion in CO₂ floods.⁵⁸⁻⁶¹ For CO₂-foam to propagate through a reservoir at a satisfactory rate, mitigation of the loss of foaming agent by adsorption is a critical factor. As a common practice, most foam applications involve preinjecting a sufficient amount of foaming agent into the reservoir to precondition the reservoir, which usually increases the surfactant expense substantially. Therefore, use of a lower-cost sacrificial agent is economically necessary to minimize the loss of costly foaming agent and ensure a satisfactory foam displacement.

Lignosulfonate, an inexpensive byproduct of the paper industry, has been used as a sacrificial agent in surfactant flooding processes. Because of its preferential adsorption onto reservoir rock, significant reduction of surfactant loss was reported in several surfactant flooding applications⁶²⁻⁶⁴ where the lignosulfonate minimized the loss of primary surfactants due to adsorption. The use of lignosulfonate as a sacrificial agent in CO₂-foam application was first reported in a recent patent by Kalfoglou et al.⁶⁵ Their preliminary data showed that the loss of foaming agent to adsorption on a limestone rock sample could be reduced by 16 to 35% when lignosulfonate was used as a sacrificial agent. To examine the feasibility of using lignosulfonate with another foaming agent (surfactant ChaserTM CD1045) and rock type (Berea sandstone), we conducted laboratory experiments to investigate 1) the compatibility of lignosulfonate with this foaming agent, 2) the efficiency of the resulting surfactant mixture in the oil recovery process, and 3) the cost effectiveness of using lignosulfonate to reduce the loss of surfactant CD1045 due to adsorption. The laboratory tests consisted of three systems: 1) a foam durability test, 2) a coreflooding experiment, and 3) surfactant adsorption measurement test. The description of experimental designs and results are presented in following sections accordingly.

FOAM DURABILITY TESTS

The primary foaming agent tested is the surfactant ChaserTM CD1045, which was identified as one of the best foaming agents in several other studies.^{56,57,66} It was supplied by Chaser International as 46.7 wt% active aqueous solution. The lignosulfonate used in this study is Lignosite[®] 100 calcium lignosulfonate, which was obtained from the Georgia-Pacific Corporation. This product is produced by sulfonation of softwood lignin; the company provides it in a powder form. All surfactant solutions were prepared with synthetic brine consisting of 1.5 wt% NaCl and 0.5 wt% CaCl₂.

A high-pressure test apparatus developed in-house⁶⁷ was used to determine the properties of lignosulfonate, mixed surfactants (lignosulfonate with ChaserTM CD1045), and properties of foam generated by these surfactants. The apparatus consists of a CO₂ source tank, a visual cell made from a transparent sapphire tube, a buffer solution cylinder, and a Ruska pump. The major part of this system, the CO₂ tank and the sapphire tube high-pressure cell, is contained in a temperature-controlled water bath. The buffer solution cylinder and the Ruska pump are installed outside the water bath and their temperatures are maintained at the test temperature through another temperature control system.

During operation, the sapphire visual cell is first filled with the solution to be tested. Once the system is brought to the desired pressure by means of the Ruska pump, the dense CO₂ is introduced through a needle at the lower end of the cell. The CO₂ is drawn upward inside the cell when the Ruska pump is in a withdrawing process. Because of the density difference between dense CO₂ and tested solution, CO₂ bubbles form and collect at the top of the cell. Depending on the effectiveness of the surfactant, these bubbles will then either form a layer of foamlike dispersion at the top of the sapphire tube or coalesce into a clear layer of dense CO₂. After a standard volume of CO₂ (1.75 cc) has been introduced into the sapphire tube, the pump is stopped and the duration of formed foam is measured.

This test provides a quick way to screen surfactants for foaming, to determine the stability of foam and other valuable information such as the interfacial tension (IFT)

between a surfactant and dense CO₂, and to obtain the critical micelle concentration of a surfactant. All the screening tests were performed at 77°F and 2000 psig.

RESULTS AND DISCUSSION OF DURABILITY TESTS

Figure 1 presents the results of IFTs between surfactant and dense CO₂ as a function of surfactant concentration. On this graph, the IFT of surfactant CD1045 decreases monotonously with the surfactant concentration and levels off at a region where the IFT no longer decreases as the surfactant concentration increases. This concentration, at which the interfacial properties between surfactant and CO₂ show no significant change, corresponds to the critical micelle concentration (CMC). Based on the data on this graph, the CMC of surfactant CD1045 was determined to be in the neighborhood of 0.07 wt%. The CMC of lignosulfonate was undetermined, as the IFTs above 10 wt% concentration were not measured. The dark color of the lignosulfonate solution at concentrations above 10% prohibits the observation of the CO₂ bubbling in the visual cell; as a result, the IFTs could not be determined.

Figure 2 presents the results of static decay of the CO₂-foam using lignosulfonate as a foam former. The graph shows the percentage of the original foam volume remaining as a function of indicated time. The lignosulfonate itself is a weak foaming agent; the bubbles formed at lower concentration coalesced in less than a minute, while bubbles formed at higher concentrations lasted less than 10 minutes.

When surfactant CD1045 was mixed with lignosulfonate solution at different concentrations, the foam bubbles decayed faster at high lignosulfonate concentrations but stabilized at low concentrations. The typical foam decay results of mixing 0.025 wt% CD1045 with different concentration of lignosulfonate are shown in Fig. 3. On this graph, the initial foaming ability decreases as the lignosulfonate concentration increases. When lignosulfonate concentration in the mixture was below 1.25 wt%, most of the foam bubbles remained intact for at least 90 minutes. The decrease of foaming ability and foam stability suggests that the surfactant mixture becomes less surface-active when more lignosulfonate is dissolved in the surfactant solution. Based on these screening

results, 0.5 wt% lignosulfonate was selected for further tests in coreflooding and adsorption experiments.

COREFLOODING EXPERIMENT

A high-pressure coreflood apparatus was designed to conduct CO₂-foam experiments on a composite core system with a known heterogeneity. Detailed description of this apparatus has been provided in previous publications^{55,66} where experiments showed that foam improved the oil recovery in a well-defined heterogeneous core system. To continue the tests of using lignosulfonate with foam in oil displacement process, a new noncommunicating-layered composite core system with a permeability contrast of 10 between the two regions was prepared. To prepare this core system, a fired Berea sandstone core was first epoxied and cast in a stainless steel sleeve. A 0.875 in. central hole was then drilled end-to-end. An annular brass pipe (0.875 in. OD, 0.563 in. ID) was cast inside the annulus core as a barrier. Finally the center was filled with relatively uniform (90-120 micron) glass beads. A summary of this core sample's properties is given in Table 1.

Tests were performed at a constant injection rate for either CO₂ alone, CO₂/brine, or CO₂/surfactant with a volumetric ratio of 4:1 at a typical Permian Basin reservoir temperature and pressure (101°F and 2100 psig). Prior to each flooding experiment, the composite core was first saturated with brine and then displaced with crude oil to establish a residual water saturation condition. The crude oil was filtered Sulimar Queen dead oil with a density of 0.83 g/cc and viscosity of 2.9 cp at the test condition. The brine was a synthetic solution with composition of 1.5 wt% NaCl and 0.5 wt% CaCl₂ in distilled water. The foaming agent was either surfactant ChaserTM CD1045 or a mixture of lignosulfonate and CD1045.

RESULTS AND DISCUSSION FOR COREFLOODS

To examine the effectiveness of using foam with and without lignosulfonate on oil recovery, the experiments were conducted in the sequence shown in Table 2. The breakthrough times of CO₂ for both regions of the composite core in each test are also summarized in this table for comparison. Because of the unfavorable mobility ratio between CO₂ and the displaced fluid, accompanied by heterogeneity, CO₂ tends to channel through the higher permeability region. As shown in Test #1 (Table 2), breakthrough of CO₂ occurred earlier at 0.26 pore volume (PV) in the high permeability zone (center) and was not observed in the low permeability zone (annulus) when CO₂ alone was used as a displacing agent. Coinjection of CO₂ and brine (Test #2), simulating a rapid cycle of WAG in the field, slightly delayed CO₂ breakthrough to 0.42 PV in the high permeability region. When surfactant (0.25 wt%) was added to the brine (Test #4), foam displacement significantly diverted part of the injected CO₂ from the high permeability zone to the low permeability region. As a result, breakthrough of CO₂ in the high permeability region occurred at 0.48 PV while production of CO₂ in the low permeability region started at 3.32 PV. The diversion of displacing fluid into the low permeability region is also evidenced by the oil production history from the annulus region of the core. The pressure profile in Fig. 4 indicates that foam started to form after about 2.6 PV of coinjection of surfactant and CO₂. No production of oil was observed in the low permeability region during this period. When foam started to stabilize in the high permeability region (center) and became stronger (as indicated by the increase of pressure drop across the core), a larger fraction of the injected fluid was diverted into the low permeability section where CO₂ and oil were produced. More oil was produced at a later time as the viscous force (pressure drop) increased.

The diversion of CO₂ by foams was not effective when a low concentration of surfactant alone (0.05 wt%) was used. However, when 0.5 wt% lignosulfonate was injected with foaming agent CD1045 at low concentration (either 0.025 wt% or 0.05 wt%), production of CO₂ in the low permeability region was observed in less than 1 PV of foam injection. An earlier production of oil in the low permeability region (annulus)

suggests that the displacement of foam is more uniform than that without coinjection of lignosulfonate. As shown in Fig. 5, 0.4 PV of oil was produced from the annulus (low permeability region) when 1 PV of foam volume was injected. This earlier oil production results from a higher-pressure drop at the earlier stage of foam displacement, which might be attributed to some synergetic mechanisms that enhance the foam properties.

Using lignosulfonate with surfactant CD1045 in a foam displacement reduces CO₂ channeling and corrects the problem of nonuniformity in a displacement associated with the rock heterogeneity. As a result, the total oil production from the composite core is improved. As shown in Fig. 6, 98% of the total oil was recovered after 4 PV of CO₂ foam was injected with 0.05 wt% surfactant CD1045 and 0.5 wt% lignosulfonate. Without coinjecting the lignosulfonate, a much higher surfactant concentration (0.25 wt%) and more pore volume (8 PV) of foam injection are required to achieve a comparable result. The cost saving in reducing the amount of surfactant (as much as 80%) and pore volume injection (50%) demonstrated by these results suggests the desirability of using lignosulfonate with CD1045 as a cost-effective design in foam flooding process.

SURFACTANT ADSORPTION MEASUREMENT

Surfactant adsorption was measured by two methods. A circulation method was used to determine the amount of surfactant adsorption under equilibrium condition and establish an adsorption isotherm. A flow-through method was used to assess the surfactant adsorption under dynamic displacement condition.

As shown in Fig. 7, the circulation experimental apparatus consists of a closed system of: 1) a given solution having a known weight in a flask, 2) a core of known volume, and 3) a metering pump. At beginning of the experiments, brine was first circulated through the core at a constant rate of 15 cc/hr. After 24 hours of circulation, a known weight of brine was removed from the system and was replaced with a known amount of a known concentration of surfactant solution. After another 24 hours of circulation, another sample was removed from the system and more surfactant was added.

The cycle of sampling and adding was repeated until no significant additional surfactant was adsorbed and the surfactant adsorption isotherm was established.

Lignosulfonate concentration was determined by UV absorbance. Lignosulfonate has a characteristic absorbance maximum at about 232 nm and 283 nm. The wavelength of 283 nm was used in all measurements to minimize any possible interference of surfactant CD1045 during the analysis of surfactant mixture. The colorimetric method (visible absorbance) was applied to analyze surfactant CD1045. This method relies on the formation of an ion pair by the anionic surfactant component in CD1045 and a cationic dye (dimidium bromide). The ion pair is extracted into organic solvent (chloroform) and change its color from transparent to pink. The content in this organic solvent is later analyzed with a spectrophotometer at the wavelength of 520 nm.

In the flow-through experiment, an in-line refractometer was added to downstream of the core sample (as shown in the circulation apparatus) to determine the effluent profile of either a tracer or a single surfactant solution. The flow-through experiment started with injection of a tracer, followed by injection of brine solution, surfactant solution and ended with injection of brine solution. A synthetic brine consisting of 1.75 wt% NaCl and 0.5 wt% CaCl_2 was used as a tracer solution. The effluent samples were collected in vials and further analyzed by spectrophotometric method to verify the results as determined by the refractometer.

All adsorption tests were conducted at 77°F and ambient condition. A 1.5 in.-diameter, 2.375 in.-long Berea core with 500 md permeability and 15.8% porosity was used as an adsorbent. The same core was repeatedly used for all the experiments. Between experiments with different surfactant circulation, a sufficient amount of brine (at least 1000 cc) was injected to clean the core.

RESULTS AND DISCUSSION FOR ADSORPTION

In the first series of experiments, the circulation method was used to establish an adsorption isotherm and to determine the amount of surfactant adsorption under equilibrium condition. Figure 8 presents the adsorption results for lignosulfonate and

surfactant CD1045. The data presented on this graph are determined at equilibrium concentrations. Overall, the amount of lignosulfonate adsorbed is less than that of surfactant CD1045. The adsorption of surfactant CD1045 is represented by a typical S-shaped isotherm while lignosulfonate reaches a local maximum adsorption at approximately 1 wt%.

In the second series of circulation experiments, the surfactant circulation scheme was varied; the sequences of circulation for each test are summarized in Table 3. The selective adsorption of surfactants was investigated by alternating the circulation sequence. In the case where CD1045 was circulated alone, the surfactant loss due to adsorption was used as a basis for comparison. The results are summarized in Fig. 9 where the horizontal axis represents the equilibrium concentrations of surfactant in the core sample at the end of each injection scheme. The plot clearly shows the effect of injection sequence on the adsorption of the primary foaming agent CD1045. When CD1045 was circulated alone, the resulting surfactant loss was the highest among the three schemes. The amount of adsorption was reduced slightly when 0.5 wt% lignosulfonate was coinjected with CD1045. The surfactant loss was reduced further when the core was preflushed with 0.5 wt% lignosulfonate. The presence of lignosulfonate reduces the available sites of adsorption on the pore surface for CD1045; thus it reduces the loss of surfactant CD1045 due to adsorption. Furthermore, a properly designed injection scheme will reduce the expense of surfactant loss due to adsorption. As the results in Table 4 show, coinjection of lignosulfonate reduces the adsorption of CD1045 from 1523 to 1023 lb/acre-ft at 0.05 wt% and from 2257 to 1713 lb/acre-ft at 0.1 wt%. The cost saving of surfactant varies from 24 to 30%. On the other hand, preflushing the core with 0.5 wt% lignosulfonate reduces the adsorption of CD1045 from 707 to 490 lb/acre-ft at 0.025 wt%, 1523 to 598 lb/acre-ft at 0.05 wt%, and from 2257 to 1388 lb/acre-ft at 0.1 wt%. The cost saving of surfactant becomes more significant as it varies from 30 to 60%. These adsorption results suggest that preflushing the core with lignosulfonate is more efficient in reducing the cost of surfactant loss than coinjecting lignosulfonate with the foaming agent.

In the flow-through experiments, the adsorption and desorption of surfactant was characterized by the area embedded between the tracer profile and surfactant profile. Figure 10 presents the adsorption curve of lignosulfonate along with the tracer breakthrough curve. The adsorption amount of lignosulfonate was calculated to be 12.1 mg. On the other hand, Fig. 11 presents the desorption curve of lignosulfonate and tracer solution. The calculated desorption amount of lignosulfonate was 12.7 mg. No significant difference between the adsorption and desorption result indicates that the adsorption of lignosulfonate is likely a reversible process. Similar results were also observed for the surfactant CD1045. The adsorption and desorption curves of surfactant CD1045 along with tracer solution are presented in Fig. 12 and 13, respectively. The calculated results from the adsorption and desorption also indicate that adsorption of CD1045 on the rock is a reversible process.

The results presented here are part of a preliminary study on using lignosulfonate as a sacrificial agent in CO₂-foam application. Although the data are limited, the favorable results from flooding experiments and adsorption measurements indicate that using lignosulfonate in a foam application enhances the foam properties, assists to correct the nonuniform displacements resulting from the rock heterogeneity, and reduces the loss of the primary foaming agent due to adsorption. The preliminary tests indicate that in the field application, it could be beneficial to preflush the reservoir rock with lignosulfonate prior to coinjecting the primary foaming agent with the sacrificial agent for a foam displacement.

CONCLUSIONS

1. Lignosulfonate is a weak foaming agent, generating CO₂ foam bubbles at 2000 psig. When used with foaming agent CD1045, the stability of foam is not affected at the lignosulfonate concentrations below 1.25 wt%.
2. When lignosulfonate is used with surfactant CD1045 in foam flooding experiments with a dual permeability composite core system, smaller amounts of primary foaming

agent and lower foam injection volumes are needed to improve oil recovery from the low permeability region.

3. Lignosulfonate can be used as a sacrificial agent to reduce the adsorption of primary foaming agent CD1045.
4. Preflushing the core with lignosulfonate reduced the loss of surfactant CD1045 more than injecting both lignosulfonate and surfactant CD1045 together.

SECTION 2

TEAGUE-BLINEBRY IMPROVED OIL RECOVERY FEASIBILITY STUDY

ABSTRACT

A project to review previous work, perform additional laboratory tests, and identify pay from well logs in the Teague-Blinebry field was performed at the Petroleum Recovery Research Center (PRRC) of New Mexico Tech. Recovered core from one well and well logs from across the field were evaluated. Laboratory tests included:

1. Mineralogy, fracture systems, and oil stains described for 251 ft of recovered core.
2. Slabbed core scanning minipermeametry on 79 samples, air permeabilities on both ends of twelve plugs, brine permeabilities on two samples, and water and CO₂ floods on two samples.
3. Minimum miscibility pressure determined to be the higher of 1000 psig or the system bubble point pressure.
4. Wettability index determined to be -0.608.

Core permeability measurements identified very low matrix permeability in the Blinebry dolomite. Regions of conductive vugs and fractures were detected. Tests indicate that even apparently filled fractures play a significant role in fluid movement. This observation is supported by effective permeability results derived from step rate tests to be 1.15 md; well above the average matrix permeability.

Density/neutron and induction or laterologs were used to identify pay in 18 wells with modern log suites. In order to include a greater number of wells, a procedure was adopted in which field average parameters were used with 57 sonic porosity logs from the older wells lacking density/neutron data. Net pay and original oil in place (OOIP) were calculated for 65 wells. Targets for potential water or CO₂ flood development are identified as the upper one-third of the Blinebry.

INTRODUCTION

The Blinebry formation in the Teague Field is located in southwestern New Mexico in Lea County. The first Lamunyon property wells were put on primary production in 1938. The field is in the final stage of a 20-acre infill drilling program. Ultimate primary recovery is expected to be less than 10% of OOIP. The purpose of this study was to examine the possibility of profitably increasing the oil production by the injection of water and/or CO₂. An earlier study had indicated that, because of low permeability and mixed or strongly oil wet conditions, a waterflood was not expected to produce significant oil and CO₂, though a possible flooding agent, was expected to be marginally profitable. This study revisits earlier work to obtain better reservoir characterization, to determine OOIP, and to run tests on core samples to determine the feasibility of water and CO₂ injection on a core level. Future studies could model the primary production and then predict if any injection process would be profitable.

RESULTS AND DISCUSSION

Core Description

Core taken from the Teague-Blinebry Lamunyon 50 well in 1989 was examined at the PRRC. Core was recovered from 5280.0 ft to 5399.0 ft and from 5455.0 ft to 5587.0 ft. Every segment of the core was examined and segments with clear fracture traces on the top or bottom were measured to obtain strike angles.

Examination of the core reveals a dolomite composition, with zones of fractures that are partially to completely filled by anhydrite. There are also conspicuous nodules of anhydrite, stylolites, a few fossils, and some zones of visible small-scale vugs. There are subtle changes in texture along the core but the composition is primarily dolomite. There are a few zones that show a shaly material, but they do not correlate to the gamma ray measurements made earlier on the core.⁶⁸ These are thought to be dark organic-rich deposits attributable to storm surge events.

Fractures over the entire core interval were found to be approximately twice as abundant on the NW-SE trend than the NE-SW trend. Zonation by narrow depth intervals

failed to reveal any clear trend. It is not known how the fracture distribution effects fluid flow in the Blinberry formation. Further examination of fracture filling minerals by thin section, study of fracture history, and additional laboratory fracture testing are required to make this determination.

Thin sections taken from 12 depths showed the matrix is composed of dolomite, which ranges in texture from microcrystalline to pelloidal. Quartz is present as silt in some samples. Porosity varies but tends to be less than 10%. Anhydrite is the most common pore and fracture filling material.

Core Air Permeability

Intervals along the core were selected for minipermeameter analysis based on the following criteria: presence of oil and permeability according to Core Labs special core analysis, visual indications of high permeability zones and fractures, and proximity to well-bore perforations. Seventy-nine intervals were investigated between 5278.3 ft and 5580.3 ft. Core plugs to be used in coreflooding were selected from 12 depths.

Scanning minipermeameter measurements were performed on the slabbed core by centering the instrument's scan pattern on the depth. The typical scan pattern used was a 3.0 in. by 1.0 in. rectangle with increments of 0.25 in. and 0.5 in. respectively. The 3.0 in. side was aligned with the axis of the core. This scan pattern yields a data set of 39 measurement points. The minipermeameter was a PRRC design^{69,70} with a probe tip that has an interior diameter of 0.25 in. and an outside diameter of 0.375 in.

Two trends are evident in the permeameter data. The first are data sets with a normal distribution. These results were associated with intervals with a standard deviation that was less than the average permeability. These do not show significant fractures or large vugs. The second trend is with a standard deviation that exceeds the average value of permeability for the interval. These intervals have fractures and/or small-scale vuggy porosity. Near-probe effects due to high conductivity features (fractures or vugs) that cross the seal at the probe tip dominate the instrument response in these intervals. These permeability values are considered to be artificially high. These will be discussed further

in a later section on fracture conductivity. Figure 14 illustrates the trends in the minipermeameter data. All of the measurements reflecting the characteristics of the matrix dolomite are characterized by permeabilities rarely exceeding 1 md, and it should be understood that the radius and depth of investigation at the probe tip is severely constrained under these circumstances. Permeability values less than 0.05 md are at the instruments lower limit of detection.

Core Plug Brine Permeability

Brine permeability tests were conducted on eight core plug samples from Lamunyon 50. The core plugs were 1.5 in. diameter and approximately 2.25 in. long. The tests were conducted in a Hassler-type core holder with 1500 psi confining pressure. A high-pressure syringe pump was used to flow brine through the sample at a known rate. The brine composition was based on well water analysis reports for Lamunyon 50, with a total dissolved solids (TDS) of 86,820 ppm. Before the permeability measurements were taken, the samples were dried in a vacuum oven and dry weight was recorded. Wet weight was recorded immediately after the sample was removed from the core holder. Calculated permeability and porosity are found in Table 5. Permeability measurements on the order of 0.001 md are estimates due to the extremely long time (days) necessary to reach saturation and steady state differential pressure (dP) measurements.

Coreflooding

Brine permeability measurements suggested that core plug samples 5304 (upper Blinebry) and 5555 (lower Blinebry) could be successfully flooded. Samples were installed into a core holder with 3000 psi confining pressure. The core holder and high-pressure syringe pump were located in an air bath controlling at 100° F. The system plumbing was designed to minimize volume and eliminate possible storage of oil, which could strongly effect the effluent measurements. The sample outlet side was maintained at 1500 psi with a backpressure regulator. An upstream backpressure regulator was in-

stalled downstream of the injection pump so that the CO₂ mass flow rate could be easily controlled.

Brine composition was the same as that used for the brine permeability measurements. The samples were prepared by flowing Blinbry separator oil through the system at control pressure and temperature. Between 100 and 150 cc of oil was injected through the sample over a 24 hour period to ensure that oil saturation had been reached. Further aging was accomplished with the core shut in overnight while the system plumbing was cleaned to remove extraneous oil.

The sample was waterflooded until oil production ceased. Then the sample was CO₂-flooded until oil production ceased. To prepare for the repeat run, the sample was slowly blown down to ambient pressure, then oil-saturated as described above. The coreflooding results are presented in Figs. 15 through 17. Flood A for sample 5555 is not presented because the initial oil saturation is suspect, but Flood A did produce oil with CO₂.

Fracture Conductivity

The PRRC scanning air minipermeameter is designed to make permeability measurements on a flat sample on a programmable grid. The instrument may also be used to make single point measurements. This feature is utilized in a new measurement technique pioneered at PRRC. Several core segments exhibiting fracture traces on a slabbed or sliced surface were selected for study. Polycarbonate strips were made with 0.125 in. diameter ports spaced 0.375 in. on centers, see Fig. 18. The ports follow the trace of the fracture. The strip is sealed to the surface of the core with silicone RTV and allowed to cure. Measurements are made at each port by manually positioning the sample on the minipermeameter table. Ports not at the measurement point are sealed during the measurement.

Figure 19 represents an example having each point an average of three measurements. The measurements showed near-zero variance, which is an indication of an excellent probe-to-surface seal. After all ports had been measured, a ten-point average of the core matrix permeability was made adjacent to the polycarbonate strip. Small fractures or vugs

were carefully avoided in these matrix measurements. The average matrix permeability and standard deviation are listed at the bottom of the fracture measurements.

In a homogeneous isotropic medium, the flowlines from the probe tip would extend symmetrically radially and into the material. The Lamunyon 50 cores deviate significantly from this model. Due to the very low permeability of these dolomites, a more correct description of the flowlines would be primarily radial, entering only shallowly into the rock, and reemerging adjacent to the external edge of the probe tip. This is the case for the matrix measurements. The very large contrast between the fracture and matrix permeability effectively prevents flow into the matrix so that the flow is constrained to the fracture system. The polycarbonate strip eliminates any possibility that the flowline can emerge a short distance from the probe tip. Fracture structure and degree of mineralization determine the actual flow path. The practical upper limit of the instrument response is 500 md, so a measurement of 500 md is actually 500 md or greater.

To further characterize the fractures in the middle Blinbry, the sample from 5566 ft was selected for further study. This fractured sample was previously studied using the minipermeameter. Two core plugs were taken from this sample; one approximately centered on the fracture and the other representative of the unfractured matrix, as shown in Fig. 18.

The fractured core plug fell into two pieces when removed from the core drill. It was realigned and secured with vinyl tape around the circumference. The core plug was installed in a Hassler-type core holder and injected with distilled water until saturated. Steady-state differential pressure was used to calculate permeability. It was interesting to find that even though the fractured core permeability was less than 1 md, 0.53 md, it was nearly 200 times more permeable (0.530 md vs 0.003 md) than the matrix core.

Wettability

A wettability test was performed on one core plug from depth 5308 ft. Brine based on the Lamunyon 50 water analysis and reservoir crude oil from the field were used in the test. The core was saturated with brine, then brought to irreducible water saturation by

injecting oil. After aging in oil the core was placed in a brine filled imbibition cell at 100°F. Recovered oil is defined as "A." Brine was then injected to achieve irreducible oil saturation, and the oil recovered is defined as "B." The core was then placed in an oil filled imbibition cell at 100 F. Recovered brine is defined as "C." Oil was then injected and the brine recovered defined as "D."

The wettability index to water is $I_w = A/(A+B)$, [0.15/3.50]. The wettability index to oil is $I_o = C/(C+D)$, [1.40/2.15]. The relative wettability index is $WI = I_w - I_o$, -0.608. This relative wettability index demonstrates that the core sample is strongly oil-wet. This result compares well to the Core Laboratory data where the relative wettability index was found to be -0.653.

MMP Determination

Four slim tube experiments were run with the Blinbry separator oil. The slim tube used had an inside diameter of 0.25 in. and length of 40 ft, and was packed with 170 to 200 mesh glass beads. Using both CO₂ breakthrough and final oil recovery suggests the minimum miscibility pressure (MMP) of the separator oil is about 1000 psig, as shown in Fig. 20. The live oil is expected to have a similar MMP unless the bubblepoint of the oil is above 1000 psig. If the bubblepoint of the live oil is above 1000 psig, then the bubblepoint pressure is considered to be the MMP for CO₂ injection.

Well Log Analysis

A variety of Teague field well logs were available in the Log ASCII Standard (LAS) format. A review of the available curve sets suggested that the data should be divided into two groups: density/neutron (D/N) wells and sonic wells. A few wells had both D/N and sonic logs. Multiple companies recorded the D/N logs over several years. Therefore it was necessary to develop an interpretation procedure that was customized for each well. In a few cases it was not possible to derive a satisfactory porosity from the D/N logs, probably due to improper instrument calibration at the time of logging. In these cases a company-generated porosity curve was digitized at PRRC and substituted in the analysis.

The D/N logs were used to generate crossplot porosity, water saturation, pay thickness, and OOIP.

Several well logging companies obtained the sonic logs over a 30-year interval. In order to compensate for instrumental inconsistencies a sonic log calibration procedure was developed and applied during the porosity calculation. Field average water saturation was applied to the pay intervals to calculate OOIP from the sonic porosity.

The Blinebry formation interval was located in each logged well and then applied to the log analysis. The average value of the top of the pay interval is about 5270 ft. The average value of the bottom of the pay interval is about 5970 ft.

Interpretation Parameters

Log interpretations were performed using GeoGraphix Prizm log interpretation software. This software requires several parameters to perform environmental corrections and calculate derivative curves. Previous work by Core Laboratories on the Lamunyon 50 core was reviewed to determine values for the Archie parameters (m and n) and acoustic transit time (DT). A report dated April 27, 1990⁶⁸ averages four points along the core to obtain values of $m=1.73$ and $n=1.57$. Another report for July 6, 1990, gives values of $m=2.09$ and $n=1.87$ at a single point.

The values $m=1.73$ and $n=1.57$ were applied to the log analysis. This produced water saturation values that are considered to be artificially low ($S_w=10\%$). Consultation with the client field geologist suggested that the default values $m=2$ and $n=2$ should be applied to the Teague-Blinebry field, since this approach had been successful in the Permian Basin in previous log analysis. This assumption gave more realistic water saturation values.

In order to derive porosity from the sonic logs a matrix transit time was needed. Acoustic velocity measurements made by Core Laboratories on the Lamunyon 50 core were the basis for determining the matrix transit time. The core porosity values were total porosity indications as determined by the helium method at Core Laboratories. The matrix transit time was obtained from the empirical transit time to porosity transform $PHI=0.67((DT-DT_{ma})/DT)$, hence $DT_{ma}=DT-DT(PHI/0.67)$. The Core Laboratories

data and calculated DTma values are presented in Table 6. The average DTma value for these samples is 45.17 usec/ft. DTma=45.0 usec/ft was used in the sonic log analysis because this value is a better mean between the upper and lower Blinebry characteristics.

Water analysis reports were available for many wells. The water analysis reports were produced by several different companies and span the years from 1978 to 1997. In addition, Arch Petroleum supplied caught-water samples for several wells. These samples were measured at PRRC using a TDS meter calibrated specifically for Blinebry-type brines. TDS determination varied from 36 kppm to 136 kppm.

It is thought that the water samples poorly represent the Blinebry formation water. The well water composition can be strongly influenced by well treatment chemicals and contributions from adjacent formations. The best estimate for Blinebry formation water TDS is 46 kppm. This salinity corresponds to a R_w value of 0.1 Ohm-m at 110°F.

Density/Neutron Interpretation

In order to use the Schlumberger crossplot functions for compensated neutron logs (CNL) that are built into the software, several environmental corrections needed to be backed out of the neutron log. This operation was accomplished by applying functions for borehole size, salinity, mud weight, temperature, mud cake, and pressure. This procedure yielded a neutron porosity curve in limestone porosity units that was entered into the crossplot function.

In most cases the well log contained a density porosity curve. The crossplot function supported by Prizm requires a bulk density curve, so bulk density curves were calculated from the density porosity curves. If a bulk density curve was recorded in the log, this curve was used directly.

Although all the neutron logs were of the CNL type, these logs were either part of a formation density (FDC) or litho-density (LDT) tool package. The logs were recorded over a several-year time span during which the technology applied in the field was changing from FDC to LDT. Different companies also recorded the logs. Therefore it was necessary to examine each log in detail to determine which tool (FDC or LDT) had

actually been used. Because of these idiosyncrasies the density/neutron interpretation was customized for each well.

Crossplot Porosity

The software used supports both FDC and LDT crossplot porosity (PHIA) functions. The density and neutron measurements respond to both primary and secondary porosity. PHIA crossplot porosity is the best estimator of true porosity available in this study.

Water Saturation and Bulk Volume Water

Water saturation (SwA) is derived from the crossplot porosity PHIA and the true resistivity of the formation (Rt). The Blinbry reservoir is characterized by intervals of very high resistivity where the dual laterolog traces may exceed the maximum scale value and only the deep laterolog trace is recorded on the backup curve. This causes gaps in the Rt data because Rt is a function of shallow and deep laterolog and the micro SFL log. To overcome this problem a test was performed to determine if the Rt value was significantly different from the deep laterolog (LLD) value. LLD was found to be a very good estimate of the Rt. This is consistent with very shallow invasion by the drilling fluid and the extreme low permeability found from core analysis.

The Archie empirical relationship $SwA = (a * R_w / (LLD * PHIA^m))^{1/n}$ is used to obtain water saturation. The parameters a, m, and n used were previously discussed. SwA values can range from zero to 1, but normally are found between 0.15 and 1. Bulk volume water (BVW) is simply SwA multiplied by PHIA.

Sonic Log Calibration

The sonic logs proved less difficult to interpret because the data is less complex and there had been no significant technological changes over the time span represented in the field well logs. The sonic logging tool should be calibrated at the time of well logging; however, this is not always properly done. In this case a small error that can be either positive or negative is added to the interval transit time recorded on the sonic log.

Fifty-seven wells were logged with the sonic tool and 33 required calibration. Again the core well, Lamunyon 50, was used to develop the procedure for this calibration. Utilizing core data and calculated PHIA, it was determined that the sonic calibration would be executed by determining a deltacal value from two depths. The interval 5520 to 5530 ft is thought to have a true porosity of 1.0%. The interval 5880 to 5890 ft is thought to have a true porosity near 0%. If it was possible to correlate both regions to the other wells, an average calibration factor was determined. The sonic calibration was utilized in a modified Wyllie time average calculation, where sonic porosity $PHIS = ((DT - \text{deltacal}) - DT_{ma}) / (DT_{fld} - DT_{ma})$.

Cutoff Criteria and Pay

In order to determine pay intervals a series of cutoff criteria was developed. The first criteria (D/N PAY) required PHIA to be greater than 5% and simultaneously BVW to be less than 5%. The second criterion (PHIA PAY) simply required that PHIA be greater than 5%. This pay interval was calculated as a quality control check to see how much pay was excluded in D/N PAY by the BVW requirement. The third criterion required PHIS calculated with the calibrated sonic log to be greater than 5%.

Pay and OOIP

For each well a text file of pay as a function of depth was generated from each pay report. Pay versus depth is necessary to identify correlatable pay zones within the Blin-bry formation and will serve as the basis for CO₂ flood design in this field. A set of Prizm generated correlation logs was also developed.

Original oil in place was calculated for the wells with D/N logs, using the function $BBL = (7758 / Bo) * \text{acres} * PAY * PHIA * (1 - S_{wA})$, where $Bo = 1.2$ and $\text{acres} = 20$. Two wells were excluded from the calculation of the field average parameters because they have anomalous values. Lamunyon 49 has an unusually low water saturation and excessive pay thickness. Lamunyon 68 has a high water saturation and low pay thickness.

Although only porosities could be generated for the 57 sonic log wells, it is highly desirable to use the sonic wells to characterize the field due to their extensive distribution throughout the field compared to the 18 D/N wells. Therefore it was decided to use the pay thickness from the sonic logs in combination with the average barrels per acre-foot from the D/N wells to calculate OOIP. As a quality check, OOIP was also calculated using sonic pay thickness, well average sonic porosity, and the D/N field average SwA. These two methods compare to within 3% for the 57 wells. The average pay thickness per well is very similar to the D/N result (149 ft vs 147 ft). Also, both OOIP calculations mentioned above and the sonic well average are close to the D/N well average (915,291 bbl and 941,693 bbl vs 925,030 bbl respectively).

This OOIP data set and the pay versus depth data are the basis for further work toward design of a CO₂ flood. Maps of net pay derived from the D/N and sonic logs were generated. The map distribution of net pay includes a central dome and a south dome separated by a structural saddle. These features correlate generally to the structure of the Blinebry formation.

Target Zone for Future Studies

It was noted from the logs that features in the upper Blinebry (5200 to 5500 ft) are continuous across the field, while the features below 5500 ft do not correlate well. These continuous zones represent a potential flow path for displacing fluids from well to well. Also, although the upper Blinebry comprises only 40% of the potential pay zone, it contains about 70% of the net pay. These factors combined make the upper Blinebry the focus of any future study. As an example see Fig. 21, which shows cumulative oil in place versus depth for Lamunyon 50.

Effective Permeability

Results from a step rate test on Lamunyon 62 and net pay results determine the effective permeability to be $(163.91 \text{ md-ft})/(143 \text{ ft}) = 1.15 \text{ md}$. A 1989 test on Lamunyon 50 and a given viscosity of 1.49 cp provide two estimates for total fluid mobility that can be used to solve for effective permeability. By the Horner radial flow analysis, effective permeability is $(1.27 \text{ md/cp}) \cdot (1.49 \text{ cp}) = 1.89 \text{ md}$. By the derivative type curve analysis, effective permeability is $(1.40 \text{ md/cp}) \cdot (1.49 \text{ cp}) = 2.09 \text{ md}$. These values that range from 1.15 to 2.09 md are well above the average matrix permeabilities, indicating an effective permeability contribution from a fracture system.

Production Effects From Infill Drilling

Oil production data was examined for four areas of the field. In each case at least one new infill well was included and several nearby wells that had pre-1995 production data. Only oil production from 1995 through 1997 was included. No significant oil production changes were seen that could clearly be attributed to production from the infill wells. Stimulation effects due to well treatment that may be present in the older well data complicate interpretation. Another factor that must be considered is the long time-scale masking effect of the low permeability reservoir.

CONCLUSIONS

1. Air permeabilities were determined on 79 intervals using the PRRC scanning minipermeameter. Two types of permeability regions were identified. The first (normal) region had consistently low permeabilities of less than 1 md with a standard deviation that was less than the average permeability. The second region contained fractures and/or vugs that gave poor results with a standard deviation larger than the average permeability, which was usually greater than 1 md.
2. Twelve core plugs had air permeabilities determined at both ends using the scanning minipermeameter. Eight were selected for brine permeability tests; two were selected for water and CO₂ displacement tests. The two core displacement tests show that oil

can be displaced in a core from both water and CO₂ injection. The pressure drop across the core was always less with CO₂ and in each tested case CO₂ followed water injection to residual oil. In each case CO₂ produced a significant amount of oil after waterflood. In the field, it appears that CO₂ could be injected without a prior waterflood.

3. It was found that even in the well-mineralized fractures, the permeability was generally much greater than in the surrounding matrix. Two flow tests using adjacent core plugs found the brine permeability to be 0.53 md in a region with a visual fracture and 0.003 md in a region without a visual fracture.
4. A core was determined to be strongly oil-wet, comparing well to an earlier test by Core Labs with wettability indices of -0.608 and -0.653, respectively.
5. Tests determined the MMP to be the higher of 1000 psig or the system bubblepoint pressure.
6. The upper Blinebry has significantly more continuous features and net pay than the lower Blinebry, and is a prime target for future studies.
7. From net pay and results of a step rate test on Lamunyon 62 well, the effective permeability of Lamunyon 62 was determined to be 1.15 md. This value compares well with earlier work. This permeability is much greater than the matrix permeability, which is typically around 0.1 md, indicating some type of fracture system.
8. The examination of production data on wells near a new infill well is not conclusive. Most wells show no change in production that is clearly due to the infill well. This would indicate that new oil that would not otherwise be produced has been tapped. A few wells show a production change that may be related to the infill well. These may indicate interwell communication through a fracture system.

SECTION 3

HISTORY MATCHING WITH FUZZY CONTROL AND MASTER WEB

SUMMARY

History matching is a long-standing problem in reservoir simulations, where a simulator is used to model a reservoir under study. A correctly calibrated simulator provides a cost-effective tool to characterize the reservoir and obtain essential information about the reservoir. The history-matching problem is to obtain a set of suitably adjusted input parameters of the simulator to enable the simulator to correctly predict the fluid (oil, gas, water, etc.) production of the wells in the reservoir, over a period of time. Due to the sheer size of the problem, completely satisfactory results of history matching have been hard to achieve, and are usually obtained with the aid of ad hoc methods. We have conducted a preliminary study using a fuzzy controller for parameter adjustment in history matching using a DOE pseudo-miscible reservoir simulator, MASTER; our results indicate that satisfactory matches can be obtained using a fuzzy controller, implemented with human experts' knowledge, for automatic parameter adjustment. A promising approach for implementing fully automatic history matching is proposed. A software tool for configuring a web-based parallel processing system to support a soft computing technique for reservoir simulations, MASTER Web, is presented. Utilizing parallel and distributed simulation across the Internet, this novel technique not only aims to solve history matching, but solves it economically on commodity hardware or cluster of ordinary PCs, thus making it affordable for smaller independent oil companies.

INTRODUCTION

Future oil and gas production in the U.S.—and eventually, in most other oil-producing nations—will be increasingly dependent on improved oil recovery (IOR), due to the gradually diminishing reserves and the high cost of exploration and drilling new wells. This global trend, along with other factors, has contributed to the increasing acceptance of reservoir simulation as a valuable means for reservoir management. A simulator is de-

veloped to model the reservoir, and, once correctly calibrated, used to obtain essential information about the reservoir. Such information includes current reserves of oil and gas, and projected annual production of oil and gas of each well. Economic and production planning can then be carried out accordingly. As a simple example, suppose a calibrated simulator is used to estimate the current reserve of oil and the projected oil production of each well. Then the current reserve (R), divided by the total annual production (P), gives the number of years (T) that an oil company can operate, $T = R / P$.

It is therefore obviously important to correctly calibrate the reservoir simulator. Due to the size of the problem in usual reservoir simulations, however, it has been very difficult to find a suitable set of the simulator's input parameters (permeability, relative permeability). The correct calibration of the reservoir simulator hinges on finding a set of suitable values of the simulator's input parameters, such that the simulated fluid (oil, gas, production of each well matches the actual production of the well over the time period of interest. This is the well-known history-matching problem in reservoir simulations.⁷¹

The highly challenging nature of the history-matching problem can be attributed to three compounding factors:

1. The size of the problem. For a pilot area of EVGSAU,⁷¹ our history-match model, as described in the next section, consisted of a 16×16 grid in 7 separate layers for a total of 1792 grid blocks. With the permeability of each grid block assumed to be uniform (already a gross simplification) and lies in the range of 1 to 150, the total size of the solution space is $150^{1792} \approx 2^{12954}$. This is the fundamental reason why good matches have been hard to obtain.
2. Inadequate computing power. In view of the size of our history match model, any existing supercomputer will be hard-pressed for the task. This is also true for other reservoir simulation problems and for other reservoir simulators as well.
3. The need for human intervention. Due to the oversimplification that must usually be made to render a surmountable version of the problem, the simulator can be viewed from a computational standpoint—despite the underlying mathematical equations being solved—as essentially performing a blind search procedure for op-

timizing a cost function. History matching is usually done iteratively, where a simulation expert would check the output of each run, adjust the parameters, and execute the next run until a satisfactory match is obtained. The result of this human intervention is a very long turnaround and throwaway runs.

The size of the problem will never be reduced, even for small reservoirs, since accurate simulation results from fine grids. The computing power will never be adequate, at least for some time to come. (Further, many smaller oil companies cannot afford fast supercomputers and it is highly desirable to develop algorithms for history matching that can be executed on clusters of PCs.) The need for human intervention, however, is the one obstacle that can be minimized by applying advanced computational techniques. Computational intelligence (CI) is an emerging interdisciplinary field in computing that holds tremendous promise for problem solving in various areas. In contrast to traditional Artificial intelligence (AI) methods that are centered around symbolic computation and logic, CI methods emphasize "soft" computing, which, among other approaches, comprises the major approaches of neural computing, fuzzy computing, and evolutionary computing. Our objective is to develop a methodology incorporating new advanced computational techniques to improve the matching process. We will implement a fuzzy controller (or a small fuzzy expert system) for automatic parameter adjustment and investigate its performance. To get around the problem of computational power and its cost, we will use web-based simulations on a cluster of PCs.

BACKGROUND OF SIMULATOR AND HISTORY-MATCH MODEL

This section gives a condensed description of the reservoir simulator MASTER, the East Vacuum Greyburg San Andres Unit (EVGSAU) reservoir, and the history-matching problem that became the foundation for our investigation of soft computing solutions. Details of the project at EVGSAU are described by Chang and Grigg⁷¹ and their references.

Simulator MASTER

The pseudo-miscible reservoir simulator MASTER (Miscible Applied Simulation Techniques for Energy Recovery), which was supplied by the U.S. Department of Energy, is an extension of the so-called black-oil model and uses the mixing-rule approach to calculate the effective fluid density and viscosity. The readers are referred to the original report⁷³ for the detailed descriptions of MASTER.

CO₂ Injection Project at EVGSAU

The East Vacuum Grayburg/San Andres Unit (EVGSAU), operated by Phillips Petroleum Company, is the site of the first full scale miscible carbon dioxide (CO₂) injection project in the state of New Mexico. Although the overall CO₂ project performance at EVGSAU has been very encouraging, certain wells/patterns have shown anomalously high CO₂ production. A pilot area in the EVGSAU was selected in 1990 as a site for a foam field trial to evaluate the use of foam for improving the effectiveness of CO₂ injection projects. Specifically, the prime directive of the foam field trial was to prove that foam could be generated and that it could aid in suppressing the rapid CO₂ breakthrough by reducing the mobility of CO₂ in the reservoir. Operation of the foam field trial began in 1991 and ended in 1993. The response from the foam field trial was very positive, as it successfully demonstrated that a strong foam could be formed in situ at reservoir conditions and that the diversion of CO₂ to previously bypassed zones/areas due to foam resulted in increased oil production and dramatically decreased CO₂ production.

History-Match Model

The foam pilot area is an inverted nine-spot pattern with eight producers (indicated by the solid circles) and one injection well in the center (indicated by the solid triangle), as shown in Fig. 22. Well 3332-001, located at the center of the pattern, was the foam injection well. Well 3332-32 was the so-called "offending" production well which consistently flowed very strongly after each period of CO₂ injection and produced more than 80% of the CO₂ injected into the pattern. The foam pilot area of nine wells and the surrounding

16 wells (eight injectors and eight producers outside the pilot area) were included in the history match model. The layout of the wells is shown in Fig. 22.

The history-match model consisted of a 16×16 grid in seven separate layers for a total of 1792 grid blocks. These seven layers were chosen based on the type-log zonation (C-3, C-2, C-1, D, E, G, and H). Injection rates and bottomhole pressures were specified as well as constraints in the history model. The surrounding producers outside the pilot area were opened to flow at a bottomhole pressure of 150 psi from 1959 to 1979 and 1500 psi from 1980 to 1992.

FUZZY CONTROLLER FOR PARAMETER ADJUSTMENT

This section describes a fuzzy controller for automatic parameter adjustment in using MASTER for history matching. The rules of the controller are formulated empirically from a study of more than 200 runs of simulation. The purpose of a controller is to do the parameter adjustment automatically and eliminate human intervention. The benefits of fuzzy control in this application are the ability to get around the problems of complexity in formulating exact rules and to deal with situations where there are multiple meta rules that may be applicable under similar circumstances. For example, expert opinion about permeability adjustment leads to the development of three different meta-rules:

1. If both wells' outputs are too high, then choose those blocks whose reduction in permeability leads to low outputs.
2. If wells' outputs are too low, then choose those blocks whose increase in permeability leads to high outputs.
3. If one well's output is too high and the other's is too low, then choose those blocks whose alteration in permeability leads to proportional, corrective shifts of outputs.

Rules of the third type are most difficult to obtain, since many factors need to be considered before a decision is made regarding which blocks' permeability to increase and which blocks to decrease, thus the need for developing the rules empirically.

Problem Overview

This study has been restricted to the primary oil production period from 1959 to 1977. During this period, wells 8 and 12 were the only production wells. In order to reduce the size of the input parameters, the following simplifications are made:

1. The permeability ratios of each layer to the top layer are assumed to be constants based on the type log analysis.
2. The interwell permeabilities can be estimated by an interpolation algorithm, which is based on the inverse distance weighted average and the top-layer permeabilities of the 25 wells.

The first simplification reduces the input parameters from $16 \times 16 \times 7$ to 16×16 and the second simplification reduces the input parameter further from 16×16 to 25. Therefore, the only parameters being adjusted for history match are the 25 input top-layer permeability values of each well (Fig. 23). For our preliminary study of the effectiveness of a fuzzy controller for parameter adjustment, only the oil production results of wells 8 and 12 are being matched.

The controller's rule base contains sets of rules that are empirically derived on a parameter study of more than 200 simulation runs in which a single well's permeability value was altered while the rest of the 24 permeability values were held constant.

Fuzzy Controller Algorithm

The main benefits of using fuzzy control is that it is easy to design and tune, and it avoids the difficulty of formulating exact rules for control actions. The fuzzy controller's rules are empirically obtained, based on a parameter study in which a single well's permeability value was altered while the rest of the 24 permeability values were held constant. The fuzzy controller^{74,75} implemented for permeability adjustment is of the simplest kind in that percentage errors and control actions are fuzzified, but only rarely will more than one rule fire. The control action applied is thus usually only scaled by the membership grade of the percentage error in the error fuzzy set. The adaptive controller works as follows.

Step 1: Fuzzification - After a simulation is run, an error calculation is made from the simulated and historical data based on a percent error formula. Due to the period restriction, the cumulative data record, and the shape of the curves, only the final year of the simulation data (q') and the historical data (q) are needed. Thus the percent error formula is $x = (((q' - q)/q) * 100)$. For example, $((((3 - 2)/2) * 100))$ gives us $x = 50$ which is then formatted to 50%. This allows for a greater range of values for ease of use, since some changes in permeability result in very fine changes of the wells' output.

Based on empirical analysis of a collection of 200 simulation runs, the following fuzzy sets: EL (EXTREMELY LOW, $A-4(x)$), VL (VERY LOW, $A-3(x)$), L (LOW, $A-2(x)$), SL (SLIGHTLY LOW, $A-1(x)$), K (OK, $A0(x)$), SH (SLIGHTLY HIGH, $A1(x)$), H (HIGH, $A2(x)$), VH (VERY HIGH, $A3(x)$), EH (EXTREMELY HIGH, $A4(x)$) were chosen. The corresponding fuzzy set values are -4, -3, -2, -1, 0, 1, 2, 3, 4, respectively. The definitions of the fuzzy sets are listed in Table 7 and plotted in Fig. 24.

Step 2: Calculate Membership Grades - In this step we will use the error formula described above and decide which fuzzy set has the highest membership for each well. Then the corresponding fuzzy set value will be assigned to each well based on the error statistics. If an equilibrium condition is reached between two sets, the set value closed to zero is chosen.

Step 3: Rule Firing - Within the fuzzy rule base there are three types of rules: I (straight increase rules), D (straight decrease rules), and P (proportional shift rules). Based on the fuzzy set assigned to each well, we can decide the rule type that needs to be applied, as defined in Table 8. Based on the fuzzy set value assigned to each well, we can calculate the average set distance from K and decide the change degree (firing strength), as indicated in Fig. 25, that needs to be applied.

Step 4: Apply Control Action - The action taken depends on the chosen rule type and the degree change as shown in Table 9. Apply the action of the rules that have been fired—alter the parameters for the next simulation run. Note that in Fig. 25 an action has the idea of GD (great decrease), LD (large decrease), etc. In this case, the action will be applied based on the following list:

GD: great decrease	where values are altered by -60
LD: large decrease	where values are altered by -30
D: decrease	where values are altered by -10
SD: small decrease	where values are altered by -1
K: ok	where values are altered by 0
SI: small increase	where values are altered by 1
I: increase	where values are altered by 10
LI: large increase	where values are altered by 30
GI: great increase	where values are altered by 60

As an example, if we have a set of permeability data that results in H (HIGH, $A2(x)$) for both wells 8 and 12, from Table 8 and Fig. 25, we can decide that the rule type is D and change degree is I based on the average value of 2. Then, according to Table 9, the control action is to increase the permeability values for wells 10, 15, and 5 by 10. The parameter adjusted by the controller is used as input for the next simulation run, which is more likely to produce better results.

Simulation Results

Many experiments have been conducted.⁷⁶ The fuzzy controller's performance depends, naturally, on the definition of fuzzy sets for error and the definition of the fuzzy sets for control actions; therefore, the rule base needs to be fine tuned for optimal performance. Since the rules must be based on empirical observations, other factors, such as scaling factors of the controller,⁷⁷ may not be quite as critical. The basic idea of using a fuzzy controller for automatic parameter adjustment in history matching, however, has been validated by using a specific controller with crisp control actions. In this case we

were able to obtain very good matches within five iterations for the two wells over their primary production period of 18 years, as shown in Figs. 26 and 27. Previously, with manual adjustment, such close matches would easily take several weeks to a few months to achieve.

MASTER WEB

Many different techniques for constructing high-performance computing systems from workstations or commodity PCs have been developed. However, these techniques have mostly not been used by independent oil producers, especially the smaller ones, for performing reservoir simulations. This is because the techniques are usually more complicated than necessary—consequently hard to learn and hard to maintain; or they require specialized hardware (e.g. networks of heterogeneous workstations) or specialized software (most of them are Unix- or Linux-based). Mostly, a typical independent oil company's computing system would comprise different-generation PCs on the Wintel (Intel chips running Windows) platform.

Our objective is to develop a practical, easy-to-use, web-based technique to connect any number (up to a few hundred) of Wintel PCs to conduct the reservoir simulation and history matching. For history matching using MASTER Web, shown in Fig. 28, a loosely-coupled (with no shared memory) parallel system configured in a master-slaves fashion, is sufficient since there is no need for inter-slave-processor communication. We use the Internet for connection and customize the browsers to build software support. Once available PCs are located, the user will have the authority to decide such matters as whether each available PC is to be connected to the cluster. The technology can be implemented on any network of ordinary PCs with Internet connection.

MASTER Web, Fig. 28, is a Windows NT-based, simulated parallel and distributed system. Its fundamental benefits are simplicity, portability, and adaptability. To the user it appears as nothing more than a set of HTML forms that return textual and graphical information, though its actual operation is more complicated. The user goes to the web-page on a server, fills in the necessary settings and info, and submits a form. The web in-

terface on the main server then runs a Common Gateway Interface (CGI) program that acts as our controller. This controller has two purposes. Its primary purpose is to run the fuzzy control algorithm, and its secondary purpose is use a combination of socket and HTTP 1.0 protocols to run the simulator on remote machines through their web interfaces. This allows for the remote machines to be of any architecture and any operating system, as long as the FORTRAN based simulator, a CGI supporting webserver, and preferably CGI script language such as PERL⁷⁸ can be run on the remote machine. As such, it is very low cost and easily implemented on nearly all systems with available freeware. This gives us a highly adaptable system, since the primary needed resource is simply a webserver. The controller that resides on the main server is designed with an NT system in mind though it can be easily adapted for other systems.

CONCLUSIONS AND FUTURE WORK

We have implemented a fuzzy controller to perform parameter adjustment for the production history-matching problem in reservoir simulations. History matching has been traditionally done with human experts' intervention to examine the results of simulation runs and manually adjust the parameters, resulting in slow turnaround and throwaway results. The fuzzy controller seeks to implement the human expert's knowledge so the time-consuming process of parameter adjustment is automated. Thus, a very large practical speedup is achieved in history matching. Our preliminary results for the MASTER simulator on the EVGSAU reservoir are highly successful and encouraging and clearly demonstrate the potential of this approach.

Our next phase of investigation will focus on the development of a neural network that will be used to self-extract rules from simulation runs. After every batch (perhaps 100 to 200) of simulation runs, the neural network will analyze the results and extract a new set of rules to update the current rule base in the fuzzy controller. This neuro-fuzzy system will allow us to implement fully automatic history matching and, hopefully, greatly improve this long-standing problem in reservoir simulations.

MASTER Web and its accompanying software tools and soft computing methods will be a valuable asset for oil and gas producers to perform reservoir modeling. It will be especially helpful to smaller independent oil companies since it makes effective, advanced computational tools available to them without requiring a heavy investment in computing equipment or software.

SECTION 4

SOLVING NONLINEAR ENGINEERING PROBLEMS WITH THE AID OF NEURAL NETWORKS

SUMMARY

In this chapter, a technique is presented for using neural networks as an aid for solving nonlinear engineering problems, which are encountered in optimization, simulations and modeling, or complex engineering calculations. Iterative algorithms are often used to find the solutions of such problems. For many large-scale engineering problems, finding good starting points for the iterative algorithms is the key to good performance. We describe using neural networks to select starting points for the iterative algorithms for nonlinear systems. Since input/output training data are often easily obtained from the problem description or from the system equations, a neural network can be trained to serve as a rough model of the underlying problem. After the neural network is trained, it is used to select starting points for the iterative algorithms. We illustrate the method with four small nonlinear equation groups, two real applications in petroleum engineering are also given to demonstrate the method's potential application in engineering.

INTRODUCTION

Artificial neural networks have recently found widespread applications in diverse areas as a practical tool for modeling, simulation, control, and prediction. Especially useful in many science and engineering applications are the backpropagation networks (BPNs),⁷⁹ which are typically trained with data or patterns collected during field operations or experiments. After a BPN is adequately trained, it can be used for the purposes of modeling, control, and prediction of the operational parameters. Sung and He⁸⁰ presented a fairly typical example of an engineering application in their paper.

Various simulation and modeling problems in science and engineering that defy simple direct solutions have traditionally been formulated as optimization problems, which include finding solutions to systems of equations or inequalities and minimizing or

maximizing functions. Solutions are obtained by solving the linear or nonlinear systems describing the problem.

There exist many iterative methods for solving optimization problems of linear and nonlinear systems.^{81,82} Frequently, however, the performance of an iterative optimization algorithm—be it derivative-based (such as Newton's method or gradient descent) or derivative-free (such as simulated annealing or genetic algorithms)—depends on the initial starting point(s). Poor selection of starting points often result in the solution process getting stuck in local minima, long iteration, or even non-convergence; while good starting points lead to fast solution. To employ iterative algorithms to solve large-scale simulation and modeling problems in science and engineering, it is therefore important to be able to obtain good starting points to ensure convergence and reduce solution cost.

This chapter presents a technique of using neural networks to aid in the iterative solution of optimization methods. Basically, the idea is to use a trained neural network to select starting points for iterative algorithms. Since input and output training data are often available or easily obtained from the problem description, a neural network can be trained to provide a rough model of the system underlying the optimization problem. After the neural network is trained, it is used to select starting points for the iterative algorithm. The technique is intended for large-scale problems that require good starting points for the iterative algorithm to achieve good performance. Applications to petroleum/chemical engineering problems are presented to illustrate this method and simulation results are also given and discussed.

NEURAL NETWORK APPROACH

A system of nonlinear equations has the general form

$$F(x) = 0 \quad (1)$$

or

$$\begin{cases} f_1(x_1, x_2, \dots, x_n) = 0 \\ f_2(x_1, x_2, \dots, x_n) = 0 \\ \dots \dots \\ f_n(x_1, x_2, \dots, x_n) = 0 \end{cases} \quad (2)$$

The solution to the above equations, $x = (x_1, x_2, \dots, x_n)$, is to be found in a certain solution space, R^n .

Suppose a suitable iterative method has been chosen for finding the solution but a starting or initial point is sought to begin the iterations. We will use a BPN to find the initial point as BPNs are widely known and used. The procedure to do this follows:

1. Select a set of points $\{x_i \mid x_i = (x_{i1}, x_{i2}, \dots, x_{in})\}$ from the system's solution space R^n . These points may be selected uniformly (within a predefined subspace), or randomly (within the whole solution space if no promising subspaces can be identified).
2. For each selected point $x = (x_1, x_2, \dots, x_n)$, evaluate $y = (y_1, y_2, \dots, y_n)$, where $y_1 = f_1(x_1, x_2, \dots, x_n)$, $y_2 = f_2(x_1, x_2, \dots, x_n)$, ..., and $y_n = f_n(x_1, x_2, \dots, x_n)$.
3. Construct the training set $\{(y_i, x_i)\}$ and use it to train the BPN. Note here that the network has n inputs $y_1, y_2, \dots, y_n$ and n outputs $x_1, x_2, \dots, x_n$. The number of nodes in the (generally) two or three hidden layers is decided from the value of n , the size of the training set, and other considerations.
4. Obtain the initial point for iteration from the neural network: setting the input $y = 0 = (0, 0, \dots, 0)$ and run the network, take the network's output $x = (x_1, x_2, \dots, x_n)$ to be the initial approximation to the system $F(x) = 0$.

The scaled conjugate gradient algorithm,⁸³ a known fast training algorithm, is employed in our experiments to train the BPN. Two hidden layers are chosen for the neural network. The connection weights are initialized with random values drawn from $(-1, 1)$. The inputs and outputs for the BPN depend on the given nonlinear system and are selected according to steps 1 and 2 above. It should be noted that BPN is not the only network architecture that can be used for this purpose; counterpropagation networks,⁸⁴ for example, can be used just as well.

To predict an initial point x to solve $F(x) = y$ is an instance of the inverse problem.⁸⁵ The training procedure seeks to implement a neural network model of the inverse system $x = F^{-1}(y)$, with y as the input pattern and x as the output pattern. The performance of the

network depends on the quality of the training set (its size and distribution of training data), the amount of training, the network's architecture, and the complexity of the transform system $F = (f_1, f_2, \dots, f_n)$.

Suppose a good training set is composed and the training is successful, i.e., convergence is reached with a high degree of correlation between the predicted and correct values of x within a reasonable amount of time. Then the initial value predicted by the neural network may be very close to the true solution of the given system. The hope is that, even in the worst case where the neural network does not model the inverse system well, it will be able to produce initial values for use such that the iterative method still exhibits improved performance, in the average case, when compared to arbitrary or random initial values.

SIMULATIONS

We begin with simple examples to illustrate the method. Four small nonlinear systems, taken from Ref. 81, are given below as Eqs. (3), (4), (5), and (6) to conduct experiments. We denote the four nonlinear equation groups as Case I, Case II, Case III, and Case IV, respectively.

$$\begin{cases} f_1(x) = 3x_1 - \cos(x_2 x_3) - 0.5 = 0 \\ f_2(x) = x_1^2 - 81(x_2 + 0.1)^2 + \sin x_3 + 1.06 = 0 \\ f_3(x) = e^{-x_1 x_2} + 20x_3 + \frac{10\pi}{3} - 1 = 0 \end{cases} \quad (3)$$

$$\begin{cases} f_1(x) = x_1^2 + 2x_2^2 - x_2 - 2x_3 = 0 \\ f_2(x) = x_1^2 - 8x_2^2 + 10x_3 = 0 \\ f_3(x) = \frac{x_1^2}{7x_2 x_3} - 1 = 0 \end{cases} \quad (4)$$

$$\begin{cases} f_1(x) = x_1 + \cos(x_1 x_2 x_3) = 0 \\ f_2(x) = (1 - x_1)^{0.25} + x_2 + 0.05x_3^2 - 0.15x_3 - 1 = 0 \\ f_3(x) = -x_1^2 - 0.1x_2^2 + 0.1x_2 + x_3 - 1 = 0 \end{cases} \quad (5)$$

$$\begin{cases} f_1(x) = x_1^2 + x_2 - 37 = 0 \\ f_2(x) = x_1 - x_2^2 - 5 = 0 \\ f_3(x) = x_1 + x_2 + x_3 - 3 = 0 \end{cases} \quad (6)$$

Experiment on Case I

Training Sets - To compare the effects of different training on the performance of the neural network, two different training sets T_1 and T_2 are constructed: For T_1 , the range of each of x_1, x_2, x_3 is restricted, arbitrarily, to $[-5.0, 5.0]$. A total of 147 training pairs (y, x) are generated and normalized to $[0,1]$ to make the training set.

For T_2 , the range of x_1, x_2 and x_3 is restricted to $[-2.0, 2.0]$; a total of 400 training pairs (y, x) are obtained and normalized to $[0,1]$. Clearly, T_2 contains samples (y, x) of the inverse system F^{-1} from a much larger neighborhood of the solution point.

Network Architecture - For each of T_1 and T_2 , a 3-layer BPN with a $3 \times 5 \times 5 \times 3$ architecture is set up with 55 connection weights, which are initialized with random values drawn from $(-1, 1)$, to train. Relative to the sizes of the two training sets, the size of the neural network is appropriate and reasonable results may be anticipated.

Iterative Algorithms - Three iterative algorithms are selected from the IMSL library⁸⁶ to run the simulations on a Sun4 Unix platform: NEQBF, NEQNF and UMC GF. These algorithms are slightly different in their uses. Each algorithm is executed with two sets of initial points selected by the neural network, with the neural network trained with different number of epochs.^{87,88}

Comparison and Results - The results of experiment on Case I are given in Table 10. It is seen that, for either algorithm, the performance of the neural network trained with 400 patterns is much better than that of the neural network trained with 147 patterns, in terms of both convergence speed and success ratio. The performance of NEQBF algorithm us-

ing arbitrary initial values is very poor. Both NEQNF and UMCGF are superior algorithms, since the success ratio is high even with arbitrary initial points, but they may converge to solutions other than the best one after a large number of iterations.

More Experiments

Similarly, we ran experiments on Cases II, III and IV. To construct training sets for the examples described above, the range of each of x_1, x_2, x_3 for each nonlinear system is arbitrarily restricted to the same domain of $[-10.0, 10.0]$. $x(x_1, x_2, x_3)$ points are then generated uniformly in the $20 \times 20 \times 20$ cube with resolutions of 0.4, 1, and 0.5 for the three cases, respectively, which give about 1.3×10^5 points for Case II, 9.3×10^3 points for Case III, and 6.9×10^4 points for Case IV. Next, the values of $y(x) = (f_1(x), f_2(x), f_3(x))$ are evaluated at those points, and only those x with $|f_1(x)| < 10$, $|f_2(x)| < 10$, and $|f_3(x)| < 10$ are retained for the three cases—such that a fairly large “neighborhood” of the solution points are sampled. Totals of 1010 training pairs (y, x) for Case II, 1306 training pairs (y, x) for Case III, and 1573 training pairs (y, x) for Case IV are obtained and normalized to $[0,1]$ to make the final training sets for neural networks, respectively. The results of the four cases are summarized in Table 11.

In terms of number of iterations, it is observed from the simulation results that the performance is much better when using initial points selected by neural networks (vs. arbitrary initial points), regardless of the size of the domains from which training data were selected for the neural networks. The number of iterations decreases by an average factor of 4. For the success ratio, a similar conclusion can also be drawn from Table 11.

APPLICATIONS IN ENGINEERING

We will present two applications of this algorithm to solve engineering problems.

Application I

The following example is taken from the nodal analysis in petroleum engineering.⁸⁹ Production systems of oil wells in oil fields are very complicated. To optimize production of an oil well, the nodal analysis method may be used. The primary step in doing nodal analysis is to solve nonlinear equation groups. A graphic method is employed in solving the nonlinear system because an iterative algorithm often fails to converge to a solution without good starting points. To easily illustrate the application in solving this problem, the well production system is simplified. The NEQBF algorithm is used in the application. Figure 29 shows an oil well production system. In this example, we choose the node at the well bottom as the solution node. It divides the whole system into two parts: inflow and outflow.

Inflow Performance - The flow of reservoir fluids in a reservoir follows the equations below (flow before the solution node).

$$q = J(p_r - p_{wf}) \quad (p_{wf} \geq p_b) \quad (7)$$

$$q = q_c \left[1 - c_1 \frac{p_{wf}}{p_b} - c_2 \left(\frac{p_{wf}}{p_b} \right)^2 \right] + q_b \quad (\tilde{p}_{wf} < p_b) \quad (8)$$

where

$$J = \frac{q_b}{p_r - p_{wf}}$$

$$q_b = (2c_2 + c_1) \left(\frac{p_r}{p_b} - 1 \right) q_c$$

$$q_c = \frac{Q_i}{(2c_2 + c_1) \left(\frac{p_r}{p_b} - 1 \right) + 1 - c_1 \left(\frac{p_r}{p_b} \right) - c_2 \left(\frac{p_r}{p_b} \right)^2}$$

Then we have

$$q = a_1 + a_2 p_{wf} + a_3 p_{wf}^2 \quad (9)$$

The oil production q and the well bottom pressure p_{wf} take values from $[0, q_b + q_c]$ and $[0, p_r]$ in this example, respectively.

Outflow Performance - Here are the flow equations in the outflow part (flow after the solution node).

$$p_{wf} = p_s + g_1(q) + g_2(q) + g_3(q) + g_4(q) \quad (10)$$

Let $g_4(q) = 0$ and we know that

$$g_1(q) = (H - L) \bar{\rho} g(1 + kq^2) \times 10^{-6} \quad (11)$$

$$g_2(q) + g_3(q) = a + \left(\frac{c}{S} + d\right) q^2 \quad (12)$$

where $d = f(q)$. Let $d = 0$. So, for a given stroke length S and under some other conditions, we have

$$g_1(q) = d_1 q^2 \quad (13)$$

$$g_2(q) + g_3(q) = d_2 + d_3 q^2 \quad (14)$$

Hence

$$p_{wf} = p_s + d_2 + (d_1 + d_3) q^2 \quad (15)$$

Finally, we have the flow equation

$$q = b_1 \sqrt{b_2 p_{wf} + b_3} \quad (16)$$

Equations used in experiment - The equations used in this example are

$$\begin{aligned} f_1 &= q - a_1 - a_2 p_{wf} - a_3 p_{wf}^2 \\ f_2 &= q - b_1 \sqrt{b_2 p_{wf} + b_3} \end{aligned} \quad (17)$$

Let $a_1 = 120$, $a_2 = -2$, $a_3 = -1$, $b_1 = 25$, $b_2 = 1$ and $b_3 = 2$, then we have

$$\begin{aligned} f_1 &= q - 120 + 2 p_{wf} + p_{wf}^2 \\ f_2 &= q - 25 \sqrt{p_{wf} + 2} \end{aligned} \quad (18)$$

In petroleum engineering, a graphics algorithm is often used to find the solution for the above nonlinear equations. The true solution of the above equations is (71.02, 6.07). p_{wf} and q take values from $[0, 10]$ and $[0, 120]$, respectively.

Neural Networks and Initial Points - Similar neural networks' architecture is used in this application. Two sets of training data from the solution domains are prepared to train the

neural network. Set 1 consists of 214 pairs of training data, taken from the value domains with resolutions of 0.05 for p_{wf} and 0.5 for q . Set 2 has 1079 pairs of training data, taken from the same domain but with a fine resolution of 0.01 for p_{wf} and the same resolution for q . Note that only those points with $|f_1| < 5.0$ and $|f_2| < 5.0$ are retained.

After the neural network is trained with the two sets of training data, two points, (72.91584, 5.95125) and (72.9594, 5.91592), are predicted accordingly, which serve as the approximate initial points for the iterative algorithm. Five arbitrary starting points, (0, 0), (30, 2.5), (60, 5), (90, 7.5), and (120, 10), are also taken from the solution domains uniformly.

Results and Summary - Similarly, experiments are conducted and results are given in Table 12. Both initial points predicted by the neural networks led the iterative algorithm to converge to the solution, while one of the five arbitrary starting points made the algorithm fail in convergence to a solution.

Using neural networks to select initial points in nodal analysis has two advantages. The iteration number is about four times smaller than the arbitrary initial points, and both of the initial points predicted by the neural networks converge to the solution. The second advantage is usually more important for engineers. Combined with an iterative algorithm, the neural network approach can be used as a way to directly find solutions of nonlinear equations in nodal analysis without user interference; as such, it makes the calculations easier and faster.

The prediction of the neural network trained with a larger set of training pairs (the relative errors are -0.002% for q and 0.827% for p_{wf}) could achieve a more accurate solution than that achieved by the neural network trained with a smaller set of training pairs (the relative errors are 2.669% for q and -1.956% for p_{wf}). This indicates that a well-trained neural network leads to a better result than a poorly trained neural network does.

Application II

In this section, we use the method to solve a nonlinear equation group encountered in equations of state calculations.

Equations of State - Equations of state (EOS) are widely used to describe phase states of materials in petroleum and chemical engineering. A hydrocarbon system usually consists of dozens, hundreds, or even thousands of components, such as methane (C_1), ethane (C_2), propane (C_3), butane (C_4), pentane (C_5), hexane (C_6), heptane (C_7), octane (C_8), nonane (C_9), and decane (C_{10}). Therefore, the number of equations is usually large. To solve EOS, *ad hoc* methods such as trial-and-error are commonly used, since an iterative algorithm often fails to converge to a solution without good initial points. To illustrate the application in this EOS problem, the NEQBF algorithm is used in this application.

The following EOS describes a real hydrocarbon system⁹⁰:

$$\left\{ \begin{array}{l} f_1 = \frac{0.4404}{8.1 - 7.1N_I} - x_1 \\ f_2 = \frac{0.0432}{1.65 - 0.65N_I} - x_2 \\ f_3 = \frac{0.0405}{0.59 + 0.41N_I} - x_3 \\ f_4 = \frac{0.0284}{0.23 + 0.77N_I} - x_4 \\ f_5 = \frac{0.0174}{0.088 + 0.912N_I} - x_5 \\ f_6 = \frac{0.029}{0.039 + 961N_I} - x_6 \\ f_7 = \frac{0.4011}{0.003 + 0.997N_I} - x_7 \\ f_8 = 1 - (x_1 + x_2 + x_3 + x_4 + x_5 + x_6 + x_7) \end{array} \right. \quad (19)$$

An approximate solution for the above equation group, obtained by trial-and-error, is (0.1110, 0.0399, 0.0489, 0.0419, 0.0281, 0.0485, 0.6877, 0.582). The nonlinear system has eight unknowns, all of which take values from the domain [0,1].

Neural Network and Initial Points - An $8 \times 10 \times 10 \times 8$ neural network was used. A total of 1181 pairs of training data, taken from the solution space with a resolution of 0.005, were gathered. Only those points with $|f| < 0.1$ were retained. Nine arbitrary initial points and 10 random initial points were then selected for performance comparisons.

Results and Discussion - Experiments were conducted, similar to Application I described earlier. Using a neural-network-selected initial point results in fast convergence to the solution (only two iterations); see Table 13. Results of using arbitrary initial points and random initial points are in Tables 14 and 15, respectively. The comparison of results is summarized in Table 16.

For arbitrary inputs, one-third of the nine starting points led the algorithm to fail, while two-thirds of them led the algorithm to the solution with an average of 13 iterations. For random inputs, the performance is similar, either in terms of success ratio or in terms of iteration number. Two out of the 10 starting points led the algorithm to fail; while four-fifths of them led the algorithm to the solution with an average of 11 iterations.

It should be noted that, to be a solution, all components of the solution vector X must be < 1.0 (boldfaced entries in Table 14 and Table 15). Hence, cases 2, 5, and 8 in Table 14 as well as cases 2 and 10 in Table 15 are not the solution.

CONCLUSIONS

We have proposed a technique of using neural networks to obtain the starting points for iterative algorithms to solve nonlinear systems. Several small examples and two actual applications in petroleum engineering were used to get simulation results for illustration. In the equations of state application, using neural networks to select initial points resulted in a greatly reduced number of iterations; further, neural-network-predicted initial points always led the algorithm to converge to the solution, while not all arbitrary and random initial points do. The savings in time and effort may be very important to an engineer when he performs such calculations. Thus, our method has the advantages of faster

convergence and higher success ratio. Note that in both applications, using trained neural networks to select initial points resulted in greatly reduced number of iterations, about four to six times.

When combined with an iterative algorithm, the neural network method for initial point selection can be employed to replace ad hoc or manual methods, such as trial-and-error or graphical, in solving a nonlinear equation group. Even though the examples presented here are too small to justify the added cost of training neural networks, the method holds potential for larger applications for which good initial points are essential. One example is the history matching problem in reservoir simulation^{71,72}; due to the sheer size of the solution space and the (gross) simplification that is necessarily made to render the problem manageable, the iterative algorithm for solving the problem may become highly sensitive to the initial points and usually takes a long time to find any solution. We are currently investigating incorporating the idea proposed here into a hybrid control system (comprising neural network, fuzzy logic, and genetic algorithm components) for parameter adjustment to tackle the problem.

SECTION 5

LITERATURE REVIEW AND ANALYSIS OF WAG INJECTIVITY ABNORMALITIES

ABSTRACT

As a result of research in the 1950s and 1960s, carbon dioxide (CO₂) flooding has been implemented at the pilot and project stage in the petroleum industry since the early 1970s. A plethora of articles have been produced on the problems and successes of using CO₂ as an enhanced oil recovery process. A number of the operational problems regarding full-scale implementation have been settled to some degree. The WAG (water alternating with gas) technique to improve mobility efficiency of the higher mobile CO₂ gas over the lower mobile reservoir fluids was an evolutionary step in the technical and economic implementation of CO₂ as a tertiary recovery process. This combination of two traditional immiscible processes (waterflooding and gas injection) resulted in a problem that has perplexed the industry since implementing the pilot studies in the early 1970s. A recent survey conducted by New Mexico Petroleum Recovery Research Center (NMPRRC) on CO₂ flooding indicated that injectivity abnormalities during WAG cycles has been a crucial limiting factor in many projects. Additionally the WAG process has been expanded to include most gas processes of enhancing hydrocarbon recovery – immiscible and miscible processes.

Based on the fluid flow properties of CO₂ and other IOR gases, one would intuitively expect that gas injectivity would be greater than the waterflood brine injectivity. However, in practice this behavior is not always observed. In addition, water injectivity may be higher or lower than the waterflood brine injectivity. What is more perplexing is that some reservoirs may lose injectivity and others may increase injectivity after the first slug of gas (CO₂) is injected. In addition, this phenomenon may occur on a local scale. Injection wells in the same field and reservoir may have totally different behavior. A number of researchers have studied and proposed reasons for this phenomenon over the past 20 years.

This section reviews a number of CO₂ projects, their specific characteristics, and correlates the hypothesis and theories as to the causes and expectations of injectivity behavior in various CO₂ and gas flooded reservoirs. The intent of the paper is to:

1. Provide a concise compendium to the current understanding of the WAG mechanism and predictability,
2. Provide a comprehensive single source review of the causes and conditions of injectivity abnormalities in CO₂/gas flood EOR projects,
3. Aid in formulating the direction of research, and
4. Help operators develop operational and design strategies for current and future projects as well as input parameters for simulating current and future projects.

BACKGROUND

Currently there are 87 total gas EOR/IOR projects in the U.S.⁹¹ The projects are different applications to similar technologies:

1. 66 CO₂ miscible projects
2. 10 hydrocarbon-miscible projects
3. 3 nitrogen-miscible projects
4. 1 hydrocarbon-immiscible
5. 1 nitrogen- and hydrocarbon-immiscible
6. 6 nitrogen-immiscible

CO₂ projects continue to grow in numbers. Immiscible CO₂ projects have dropped to zero while ten miscible CO₂ projects are planned as of January 1998. Brock and Bryan⁹² presented a summary of CO₂ EOR projects and reviewed the performance of 30 full-scale field projects and field pilots up to 1987. In 1992 there were 45 active CO₂ projects in the U.S.⁹³ Initially the industry outlook was pessimistic; however, by 1992 most projects had been shown to be technically and economically successful. The production performance has been better than was anticipated.⁹³

At the beginning of 1998 and based on 1997 production figures, the U.S. production from gas injected EOR was estimated at 307,544 b/d or approximately 4.7% of the total

oil production in the US. Oil production from CO₂ activity alone contributed nearly 179,000 b/d, which is an increase of 4.9% over 1996 production attributable to CO₂ production and represents 2.8% of the 1997 US oil production of 6.4 MM bopd.⁹¹

The Permian Basin of west Texas and southeastern New Mexico remains a very active area for CO₂ projects. Eight of the ten planned projects are in the Permian Basin.⁹¹ However, new CO₂ EOR projects are possible for areas of California, Kansas, Oklahoma, and the Texas Panhandle.⁹¹ The significant existing infrastructure of major CO₂ source fields, distribution pipelines, and recovery plants make CO₂ projects moderate risks in the Permian Basin.

Industry's Initial Concerns

There are two basic enhanced oil recovery techniques in gas flooding a reservoir—continuous gas injection and the water alternating with gas injection (WAG) scheme.

Industry initially had a number of concerns about CO₂ injection, especially during the WAG process, to control the higher mobility gas. Careful planning and design along with good management practices have allayed most concerns.⁹³

1. Water blocking: Water blocking initially was to be detrimental. However, WAG projects appear to be performing better than those using continuous injection. Water blocking and trapping is discussed at considerable length regarding the whys and wherefores of potential effects.
2. Corrosion: Dry CO₂ is not a corrosion problem but becomes extremely corrosive when water is present. Good management and design practices have mitigated this concern.
3. Production concerns: Experiences such as tubing plugged with gypsum and asphaltenes, rod pumps gas-locking, ESPs cycling, and premature and large amounts of CO₂ breakthrough, have not been a major factor, though they have occurred. Active monitoring and maintenance have minimized these concerns.
4. Oil recovery: Initially, the oil industry estimated CO₂ incremental oil would be 8–14% OOIP.⁹³ However, revised estimates after some years of experience and

with the evolution of more sophisticated estimation techniques indicate this could be higher.

5. Loss of injectivity: Lower injection rates of CO₂ slugs and water slugs have been a concern since CO₂ field tests were conducted in the early 1970s.⁹⁴ Currently the problem is still a concern in the management of a WAG process.³⁴ This concern is the primary thesis of this paper.

Injectivity Losses

There are two separate but related questions in regarding this perplexing issue.

1. What causes the unexpectedly low injectivity during gas injection?
2. What is the reason for the apparent reduction in water injectivity during brine injection after gas injection?

Injectivity is a key variable for determining the viability of a CO₂ project. Potential loss of injectivity and corresponding loss of reservoir pressure and possibly loss of miscibility resulting in lower oil recovery has potentially major impact on the economics of a gas injection process. Most of the projects evaluated by Hadlow⁹³ showed higher CO₂ (gas) injectivity than that obtained in pre-waterflood water injection. However, substantial loss in water injectivity after CO₂ or gas injection has been seen also. On the average, about 20% loss of water injectivity can be expected in the WAG process.⁹³ Some solutions to mitigate this are:

1. Decrease the WAG ratio (i.e., decrease the water slug and increase the gas slug), although this could cause a detrimental effect in mobility control.
2. Increase the injection pressure, which could cause fracturing of the formation and inefficient sweep.
3. Add additional injection wells

No reported project economics have been severely impaired due to injectivity loss alone.⁹³ However, this outcome could be the result of the heavy monitoring CO₂ projects receive to assure success. Optimization of operations can significantly improve the eco-

nomics of existing CO₂⁹⁵ and other EOR projects. Three major management parameters that effect the economics of a CO₂ or gas flood are⁹⁵:

1. CO₂ and water half-cycle slug sizes,
2. The GWR (WAG) profile, and
3. The ultimate injected CO₂ slug size.

WAG PROCESS DESCRIPTION

The water alternating gas injection (WAG) scheme is a combination of two traditional techniques of improved hydrocarbon recovery—waterflooding and gas injection.⁹⁶ Conventional gas or waterfloods usually leave 20–50 % of the oil as residual.⁹⁷ Laboratory models conducted early in the history of flooding showed that simultaneous water/gas injection could have a sweep efficiency as high as 90% for a five-spot flooding system. With gas alone the sweepout efficiency could only be about 60%.⁹⁷ However, completion costs and the additional complexity in operations, as well as technical factors of gravity segregation, indicated that simultaneous water/gas injection was a difficult if not an impractical method to minimize mobility instabilities associated with gas flood process. Therefore the use slug (WAG) has been adopted, although this process also has inconveniences. The strategic implementation of the WAG process is paramount in the operation and economic maintenance of EOR projects.

The planned alternating of water and gas in ratios of 0.5 to 4 in frequencies of 0.1 to 2% pore volume slugs of each fluid⁹⁸ can cause water saturation increases during the water cycles and decreasing water saturations during the gas half of the WAG cycle. The displacement mechanism caused by the WAG process occurs in a three-phase regime and the cyclic nature of the process creates a combination of imbibition and drainage.⁹⁶ Optimum conditions of oil displacement by WAG processes are achieved if the gas and water have equal velocity in the reservoir. Because of various reservoir factors, the optimum conditions may occur in the reservoir to a limited extent, usually in the water/gas-mixing zone.⁹⁹ Thus the optimum WAG design is different for each reservoir and needs to be determined for a specific reservoir and possibly fine-tuned for patterns within the reser-

voir. There are a number of different WAG schemes to optimize recovery. UNOCAL patented a process called HYBRID-WAG where a large fraction of the pore volume of CO₂ to be injected is injected followed by the remaining fraction divided into 1:1 WAG ratios.⁹⁸

The important technical factors effecting WAG performance are

1. Heterogeneity (stratification and anisotropy)^{95,96,99-102,121,122}
2. Wettability^{96,99,102,103}
3. Fluid properties^{95,99,100,121,122}
4. Miscibility conditions^{95,96,99}
5. Injection techniques^{95,96,99} (tapered WAG design as opposed to a constant WAG design)
6. WAG parameters^{95,96,99}
7. Physical dispersion¹⁰⁰
8. Flow geometry (linear, radial and pattern influence)^{95,100,101}

Optimization of WAG

Oil recovery is enhanced if the gas and water slugs are appropriate for a specific reservoir. Gorell,¹⁰⁵ using a 1-D simplified model, assumed that the WAG could be analyzed as if it behaves like simultaneous solvent-water injection. Admittedly, the validity of this assumption depends on the relative size of the injection cycles. From Gorell's study, equal WAG ratios are more efficient and are insensitive to assumed levels of trapping. Injecting below equal velocity WAG ratio is viscously unstable while injecting above the equal WAG ratio creates stability at the expense of increasing trapped oil or displacement efficiency. Since the process can create water barriers or shielding effects, a WAG cycle can have a harmful effect on achieving maximum oil solvent contact time.

Wettability effects have also been shown to affect the optimum WAG ratio.¹⁰⁶ Water-wet bead packs show an optimum WAG ratio of 0:1 or continuous gas injection. Contrarily oil-wet packs suggest an optimum WAG ratio of equal or 1:1 velocity ratios. Mixed-wet states indicate maximum recovery is a stronger function of slug size in secon-

dary CO₂ recovery than in tertiary flooding. In addition, water-wet laboratory models indicate gravity forces dominate while in oil-wet tertiary floods, viscous fingering is a controlling factor.

OVERVIEW OF WAG INJECTION PROJECTS

Simultaneous Gas/Water Injection

Injectivity improvements have been seen in waterfloods where CO₂ has been present. In particular, improvements in waterflood injectivity were attributed in comparisons of two similar carbonate fields.¹⁰⁷ In these cases the injectivity improvements were attributed to acid gases dissolved in the produced water, with the field having the higher CO₂ content also having higher injectivity. Injectivity deterioration occurred in high rate, high permeability areas. Ramsey and Small¹⁰⁸ reported improved injectivity with carbonation of water in sandstones. In addition carbonated waterfloods were suggested¹⁰⁹ as viable IOR mechanisms and have been shown to enhance conventional waterflooding. However the use of carbonated water or "fizz floods" as an EOR process does not show significant economic impact compared to a full-scale miscible gas flood or WAG EOR operations providing that miscibility can be obtained and that miscible flooding is economically viable.

The use of carbonated waterfloods has been suggested in low permeability, naturally fractured reservoirs particularly the Austin chalk.¹¹⁰⁻¹¹⁴ Additionally, the use of surfactants in carbonated water imbibition significantly increased oil recovery in rock samples with mixed or oil-wet conditions.¹¹⁵ Injection of water with dissolved gas and injection of water above the bubblepoint may result in the most even distribution of gas throughout the reservoir where oil is otherwise trapped. Improvements in the efficiency of water flooding and tertiary CO₂ flooding in heterogeneous reservoirs may also be achieved by the injection of water with dissolved gas (CO₂) or simultaneous water and gas injection (SWAG).¹¹⁶ Amoco conducted a small feasibility pilot study on carbonated waterflooding in the mid 1980s to determine potential use in the west Texas fields.¹¹⁷ Bargas, Montgomery, Sharp and Vosika¹¹⁸ published simulation results that show that for the

shallow, light-oil Salt Creek field in Natrona County, WY, recovery increases under immiscible CO₂ process and significantly increases with the use of carbonated chase water. When non-carbonated chase water is used, significantly less oil is achieved, though there is an oil increase during the immiscible CO₂ injection.

Humble Oil and Refining Co. first tried simultaneous water and enriched gas injection (SWAG) in 1963 in the Seeligson Field Kleberg County, Texas after injecting enriched gas since 1957 (note the Seeligson project was a miscible flood).¹¹⁹ Low injection rates and high pressures were experienced under simultaneous injection of water and enriched gas. During February 1964 alternate slugs of water and enriched gas were implemented in an attempt to increase rates and decrease pressures. The first cycle saw increased rates; however, during the second cycle the wells would take little gas. High water saturation around the wellbore was the attributed cause. Recently other projects using immiscible water alternating gas injection (IWAG) and SWAG have shown that they can be an effective tool in management of oil reservoirs, especially with high gas production.¹²⁰

With significant infrastructure of CO₂ or other solvent gas delivery and availability of plant process capacity in areas like west Texas, the economic incentive for a full-scale EOR project may be more technically and economically feasible even in times of depressed oil prices. However, for areas that do not have the infrastructure, initially escalating the costs several-fold, the implementation of a carbonated waterflood may economically enhance the recovery of oil over waterflooding especially in times when low oil prices prohibit immediate large initial infrastructure setup costs. The CO₂ source could come from power facilities, thus sequestering a greenhouse gas. In addition injection of water with dissolved gas and injection of water above the bubblepoint may result in the most even distribution of gas throughout the reservoir, enabling the gas to reach a large quantity of the reservoir where oil is otherwise trapped. This does not suggest that these methods are a replacement for CO₂-continuous or WAG processes but merely an enhancement of the processes as well as of the waterflood process where heterogeneities can cause severe trapping.

Gas Reservoir Uses of WAG

Conventionally, water is never purposely injected in a gas reservoir. Recently studies^{121,122} have been conducted that show that the use of the WAG processes in gas condensate recovery may improve sweep efficiency. WAG is effective in recovering significantly more condensate with less injected gas than continuous gas injection and could substantially improve economics. The process is sensitive to reservoir layering, fluid properties, trapped gas saturation and vertical permeability. These studies use a fully compositional simulator with crossflow effects. The simulation studies suggest that 78% of the OHIP can be achieved with WAG as opposed to 61% with gas injection alone. The water following the gas injection traps dry gas and not the gas condensate; gas injection is restored after water injection. In addition, corefloods constructed by layering limestone slabs of different permeability show that permeability contrasts strongly influence WAG performance. Severe channeling of injected gas in highly stratified reservoirs can be reduced by water injection. The higher the permeability contrast, the higher the incremental recovery with WAG that can be expected. If vertical crossflow is restricted, recovery improves by 54% or 71% OHIP, whereas without WAG only 46% OHIP is achieved. These studies did not include hysteresis in the gas/water relative permeability curves. Hysteresis effects would reduce gas recovery with WAG and is needed to tune the WAG process.⁹⁹

Miscible Flooding with Hydrocarbon Solvents

Use of hydrocarbon gases, particularly LPG, to develop miscibility and improve oil recovery has been evaluated since the early stages in the evolution of enhanced and tertiary oil recovery.¹²³⁻¹²⁵ The utilization of WAG in these processes was used to overcome large mobility differences between solvent displacing oil and improve ultimate recovery.

The first field application of WAG is attributed to the North Pembina field in Alberta, Canada by Mobil in 1957.¹²⁶ Whether injectivity abnormalities developed was not reported. Four rich gas, secondary pilot projects were evaluated by AMOCO^{124,125} in oil-

wet west Texas and Canadian carbonate reservoirs. Loss of injectivity in the water injection after rich gas injection was observed in only one of the subject projects—the San Andres formation. The hypothesis was that rich gas is trapped during the first cycle of water injection and causes a decrease in relative permeability to water. Remedial action was unsuccessful. The remedial actions tried were:

1. Wellbore washing for hydrocarbon cleanup with
 - A. Xylene and propane,
 - B. CO₂ following rich-gas injection to displace the rich gas with more water-soluble CO₂,
 - C. Rich gas followed with lease crude to reestablish pre-gas injection saturations
2. Acid Treatments
 - A. May have fractured well
 - B. During the second cycle of water the well's injectivity dropped
3. Operating Changes
 - A. Buffer slug of gas reduced
 - B. Initial water injection rates higher
 - C. Lower subsequent injection rates following rich gas injection

Laboratory corefloods showed pronounced reduction in water injection rates using fresh water rather than high salinity brine but injection of a more saline, produced water in the field showed no improvement.¹²⁴ The authors suggest that the problem is not a near-wellbore effect but develops further in the reservoir and any wellbore corrections may alter the injectivity only for a short time (i.e., treats the symptom, not the problem). The oil and gas saturations present act to lower the maximum attainable water saturation resulting in reduced water mobility during subsequent periods of water injection. Laboratory data support field evidence that reduced water injectivity is inherent to the WAG process for this reservoir.

Review of WAG Projects

Information from the literature regarding 22 projects is reviewed here. This is not a complete, comprehensive review of all gas injection, WAG EOR projects (see reference 126). In many cases relevant information on deducing the causes of problems is vague and data on formation parameters is often inadequate. Table 17 is a listing of information available primarily for CO₂ gas injection processes though others are listed. In a general format, Christensen et. al.¹²⁶ review 60 WAG processes up to 1998. No specific order of review is developed. Different gas injection EOR techniques are reviewed in different lithologies to obtain information on operational problems and solutions associated with the WAG process.

Mallet Unit - Located in the west Texas Slaughter field in Cochran and Hockley counties, Texas, the Mallet Unit^{127,128} is a miscible CO₂ flood that has seen injectivity reductions in CO₂ rates and subsequent water WAG half cycles compared to pre-CO₂ rates. The unit covers 4780 acres and produces from the slightly oil-wet San Andres carbonate formation at an average depth of 5000 ft. Significant tertiary response was seen eight months after the start of CO₂ in November 1991. Oil production increased from 1550 BOPD and peaked at 2200 BOPD in 1994, while gas production increased sevenfold. The large expense associated with the gas processing resulted in the need for curtailment of CO₂ production. Analysis of production data suggested a permeability trend and also the need to control flood fronts. The reduction of gas production could be accomplished by WAG tapering or the progressive reduction of gas injection with subsequent WAG cycles. The strategy was to reduce gas production, maintain duration of tertiary oil response and enhance CO₂ utilization. The results were a decrease of gas production from 7 MMSCFPD to 5 MMSCFPD while oil production increased to over 2700 BOPD. The Mallet's income doubled while lifting costs decreased by 20% on a BOE basis, with an improvement in gross CO₂ utilization.

East Vacuum Grayburg San Andres Unit - Discovered with initial production in 1938, the East Vacuum Grayburg San Andres Unit (EVGSAU)¹²⁹ is located 15 miles northwest of

Hobbs, New Mexico. CO₂ injection began in September 1985. The patterns were initially large 80-acre patterns. Initially the design was to inject a fixed 2:1 WAG ratio with a total of 30% HCPV CO₂. The cycles would be timed by injecting four months of gas and eight months of water. The CO₂ oil recovery was estimated at 21 MMSTB or 8% OOIP above the ultimate primary and waterflood recovery of 40%. Current (1995) ultimate recovery including CO₂ flooding is estimated to be approximately 150 MMSTB or (50%) OOIP. The revised estimate for incremental CO₂ project oil recovery is 30 MMSTB or 11.5% of the 260 MMSTB OOIP of which approximately 4 MMSTB or 1.5% OOIP is attributed to infill drilling.

Overall the project has been successful but the flood performance has not been uniform, with local problems of: 1) injection performance, 2) pattern balancing and sweep efficiency, 3) large swings in injection gas production rates, 4) changes in injection gas composition and MMP and 4) reservoir pressure decline (in some cases below MMP). Most of these local problems occurred due to a fixed WAG ratio and infill drilling that caused high voidage replacement ratio. High permeability thief zones only five to 10 ft in thickness that could be taking two-thirds of the injected fluid contributed to the less than desirable efficiency. Increasing each injector to maximum injection pressure limit based on the reservoir parting pressure limit decreased the voidage/replacement ratio. Smaller and more frequent cycles helped reduce large gas swings. The the WAG ratios were tailored for each pattern and maturity. Patterns with high gas production histories had WAGs as high as 4:1. Other wells in low breakthrough areas had ratios of 0.8:1.

Prudhoe Bay - The Prudhoe Bay¹³⁰⁻¹³⁶ on the North Slope of Alaska is the largest field in North America. The Sadlerochit reservoir is a sandstone reservoir and is the major producing formation at Prudhoe Bay with 30 billion reservoir barrels of oil and 17 billion reservoir barrels of free gas. Typical permeabilities are from 50 to 1200 md with porosities from 15 to 25% depending on the zone. The reservoir came on-stream in 1977 and the waterflood came on-line in late 1984 and early 1985. Ultimate recovery by waterflood is expected to be in excess of 50% in all the major flood areas. A large stream of pro-

duced gas is processed in because there is no commercial market. Initially the gas was reinjected into the gas cap to provide pressure support.

Early Prudhoe EOR screening studies started shortly after the start of field production. Four processes were considered: surfactant flooding, enhanced waterflood techniques, thermal processes, and miscible gas displacement. There are four dominant recovery processes currently at work in Prudhoe Bay: gas cap expansion/gravity drainage, waterflood, miscible flood, and gas cycling. In addition there are four major waterflood/miscible water alternating gas (WAG) flood projects in progress in the Prudhoe Bay field with a total estimated reserves of >12 billion bbl. Surfactant flooding was recognized as a potential EOR process for this reservoir but reviews did not find a surfactant effective over the range of temperatures and salinity.¹³⁰ Enhanced waterflood techniques such as carbonated, caustic, or polymer flooding were found to offer limited potential but were deemed strategically inappropriate. Thermal processes were eliminated because of the depth and pressures of the formation and characteristics of the oil. A vaporizing miscible process was determined to be inappropriate because the crude oil is low in intermediate components and because the critical pressure at which methane or CO₂ and the oil become miscible is well above reservoir pressure level. With the addition of ethane and propane to the separator gas, an injection gas is miscible with typical reservoir oil and the intermediates can be obtained from produced fluids at Prudhoe.

The flood is a miscible hydrocarbon flood that was began in late 1982 with a WAG ratio averaging 3:1. Currently (1995) the EOR project consists of more than 120 patterns.¹³³ The concern at Prudhoe Bay is that the injected gas might have a strong preference to enter the uppermost perforation and little solvent would be injected into the lower portions of the reservoir. The Prudhoe Bay is a gravity-dominated WAG process and a top-loaded solvent profile would substantially reduce EOR reserves. However, no apparent top loading of the profiles has been noted.

McGuire et al¹³⁶ describes a reservoir management method similar to huff-n-puff to improve the efficiency of gravity-dominated miscible drives. The process is called miscible injectant stimulation treatment, or MIST. The process involves completing a pro-

duction well in the bottom of a thick continuous formation. A large slug of miscible injectant is injected followed by small slug of water. The MI sweeps the rock not contacted by previous MI injection. The well is then recompleted at the top of the reservoir and returned to production. Horizontal wells are advantages in the MIST process. Results are mixed but encouraging

Kuparuk River Field - The Kuparuk River Field¹³⁷⁻¹⁴¹ is located on the Central North Slope of Alaska and like Prudhoe Bay is one the most prolific oil fields in the United States currently (1995) producing about 300,000 BOPD. The field was discovered in 1969 with development delayed till 1979 due to economic uncertainties and resource constraints tied to Prudhoe Bay. Production under solution gas drive began in December 1981. Waterflooding began in 1983 and expanded to field-wide in 1985 with the start-up of a seawater treatment plant. By 1996 over \$5 billion had been expended to drill, equip, and build support facilities for 700 wells (about half were injectors) at 42 drill sites.¹⁴¹ Production depth is about 6000 ft in a slightly dipping northwest-southeast intermediate-wet sandstone anticline with porosities of 23–24% and permeability thickness ranging from 1000 md-ft to 5000 md-ft. Reservoir temperature is about 158° C and oil gravity is about 24 API and has 3–17% asphaltene content. Both immiscible and miscible gas projects are underway in this large field. Development is on 160-acre and 80-acre patterns.

With limited market and fuel usage demands, the immiscible water alternating with gas injection (IWAG) process has been effectively used to manage gas at Kuparuk. Simulations using a fully compositional model suggest that IWAG may have an incremental effect of about 1–3% of OOIP. Field experience show that in addition to higher production rates, reduced water handling costs, and better reservoir management, a tapered WAG helps keep produced gas oil ratio manageable, provides in-situ gas lifting, suppresses water production, helps replace voidage, and can help determine well interactions.¹³⁸ Additionally, the IWAG process is effective in storing gas.

IWAG ratios are tapered and generally increase from 0.3:1 to 2:1 as patterns mature with slug sizes decreasing from 5%–2% HCPV. Each gas slug lasts 1–12 months. Ta-

pering IWAG ratios and gas slug sizes help keep wells on-line with manageable GORs. WAG scheduling has been a major work effort to balance optimal WAG injection against gas disposal need. While water injection rates are slightly reduced after start of gas injection, gas injection rates are about twice as high as water injection rates on a reservoir barrel basis.¹³⁸ Lack of water hysteresis and lower levels of trapped gas was suggested as the reason that the loss of water injectivity was less than anticipated.

To cut costs further, simultaneous water and gas injection (SWAG) was suggested.^{138,140} A pilot study was undertaken in June 1994 to ascertain the possibility of injecting gas simultaneously with water, thus eliminating the separate gas injection system. During the pilot, loss of injection rate was observed as the gas fraction in the injection mixture increased and the surface injection pressure was kept stable at about 2800 psi. The loss was attributed to lower bottomhole pressures rather than the relative permeability effects expected of two-phase flow in porous media. Trapped gas was suggested to alter reservoir fluid mobilities and improve waterflood sweep efficiency.

The Kuparuk River oil fields have also had a miscible water alternating gas (MWAG) EOR project since 1988.^{138,141} Expansion of the project from two sites to three sites was accomplished in 1993 and large scale application of MWAG at Kuparuk is in progress (mid-1996) with a project that is expected to more than triple current MWAG injection. Miscible flooding appeared appropriate since the reservoir pressure was about 3000 psi, with high residual saturation of 28–42%, plentiful enriched gas supply, and the lack of a gas cap. Injectivity predictions accounting for three-phase flow and gas trapping indicate that water injectivity should be noticeably reduced as a result of gas injection, but this effect has not been observed in the field. Water injectivity was not affected while gas injection is 15–20% higher than that of water.¹⁴¹ Incremental oil from MWAG is estimated to be 200 MMSTB.

South Welch Unit - Unitized in 1968 for waterflood initiation, the South Welch Unit¹⁴² is currently a CO₂ miscible flood producing from the San Andres formation. The full scale CO₂ flood began in September 1993 based on the performance of a 180-acre pilot from

1982 to 1987. Infill drilling developed the pattern in a 20-acre line drive pattern. The design of the flood and facility used a compositional model and matched the primary, secondary, and tertiary performance. A 1:1 WAG ratio with four-month half-cycle lengths constituted the design criteria for the South Welch field. A 38% IHCPV CO₂ slug or 50% floodable IHCPV was found to be optimal for the South Welch Unit.

South Cowden - The South Cowden¹⁴³⁻¹⁴⁵ field is located in Ector County, Texas and produces from the Grayburg dolomites and Queen sandstones. Development commenced in 1948 on 40-acre well spacing. Coreflood studies conducted on native state cores from South Cowden Unit showed that water relative permeabilities observed in the laboratory were appreciably reduced compared to values observed prior to CO₂ injection. The corefloods also indicated that trapped gas saturations of 20-25% PV could develop in South Cowden reservoir rock during miscible CO₂ WAG operations. The trapped gas is rich in CO₂, but not pure CO₂, and creates significant water-relative permeability hysteresis effects. The measured CO₂ relative permeabilities are much lower than oil relative permeability at comparable saturations. Using the lower CO₂ relative permeability data, the simulator predicted water injection rates during WAG cycle operations to be about 30% lower than the water injection rates during waterflooding, as well as significantly lower gas (CO₂) injection rates, later gas breakthrough and less gas production, and higher incremental oil recovery.¹⁴⁵ Key parameters in determining injectivity and displacement in miscible CO₂ WAG injection projects are:

1. Relative permeability to CO₂
2. Trapped gas saturation
3. Hysteresis effects

The use of horizontal CO₂ injection wells can increase injection rates severalfold over the injection rates achievable with vertical wells in a five-spot pattern.^{143,146} This is an important consideration in low permeability reservoirs or where reduced injectivity develops during WAG cycles. The South Cowden (San Andres) Unit is a DOE Class II oil program for Shallow Shelf Carbonate Reservoirs to demonstrate the technical and eco-

nomic viability of utilizing horizontal CO₂ injection wells and centralization of production/injection facilities to optimize CO₂ project economics. Better sweep efficiencies, faster flooding rates, and/or lower injection pressures are possible with horizontal wells.^{146,147} Thus the economics of EOR projects and conventional improved recovery methods may substantially improve with the use of horizontal wells.

Lost Soldier Tensleep and Wertz Tertiary Projects - The Lost Soldier and Wertz Tensleep¹⁴⁸ fields produce from the Tensleep sandstone. The average depth is about 5000 ft and is a faulted anticline. During waterflood, the water injection rate averaged 3000 BPD. After CO₂ injection, water injection began at 4000–5000 BPD and declined rapidly to 2000 BPD over the water half-cycle. CO₂ injection was controlled at 5.5 MCFD and water injection at 2000 psi. Over half the Lost Soldier wells saw injection losses while only 20% of the Wertz injectors exhibited a loss in injection.

Most of the Lost Soldier patterns are on a 1:1 GWR (gas-water ratio). Each pattern is managed on the basis of cash flow generation relative to other patterns in the field. Cumulative recovery exceeds 50% OOIP with CO₂ accounting for 9.9% as a result of 61% HCPV of injected CO₂. Ultimate recovery is estimated at 54.2%. In contrast, the Wertz field with poorer pay quality has injected 64% HCPV of CO₂ to recover approximately 9.4%.

Operational philosophy is to:

1. Maintain reservoir at a reservoir pressure of 2800 psi;
2. Manage each pattern on profitability by allocating available CO₂ into areas with the best utilization;
3. Expand into new patterns as CO₂ becomes cost-effective.

Dollarhide Devonian - The Dollarhide Devonian¹⁴⁹ CO₂ miscible flood project produces from the Thirty-one Devonian carbonate formation in Andrews County, Texas and has a history of WAG-induced injectivity losses. Because of the injection losses, WAG has been limited to areas of severe gas breakthrough. The field produces from an average

depth of 7800 ft with OOIP estimated at 145.8 MM bbls. Ultimate tertiary recovery is estimated at 20.4 MM bbls.

Two main facies separated by tight limestone are defined in the Thirty-one formation, referred to as the Lower Porosity and Upper Porosity. The Lower Porosity zone accounts for 83% of the total oil in place and is therefore the main target for tertiary oil recovery. The Upper Porosity zone shows permeabilities and porosities and net pay averaging 12 md, 8.5% and 28 ft, as compared to the Lower's measurements of 9 md, 17%, and 48 ft.

CO₂ injection flooding commenced November 1993, using the HYBRID WAG process. Tertiary response was observed nine months after initiation in one well on a 10-acre spacing, occurring in almost half the time estimated. On average, response time was 35 months for twenty-acre spacing. CO₂ production was seen 17 months after the first gas injection. Many wells outperformed the average, showing production increases of 475%, 500%, or as high as 910%. UNOCAL's operating philosophy was that the WAG process severely hinders the development of the miscible solvent bank and reduces the displacement process and also causes severe trapping and water shielding. Coreflooding tests under continuous CO₂ injection were 12–16% greater than under WAG.

Wasson Field - The Wasson Field covers 120 square miles in Gaines and Yoakum counties, Texas, on the Northwest Shelf of the Permian Basin.¹⁵⁶ The field has six EOR projects: Bennet Ranch Unit, Mahoney Lease, Wasson ODC Unit, Willard Unit, Roberts Unit,¹⁵⁰ Cornell Unit and the Denver Unit.

The Bennett Ranch Unit was formed in 1964 to install a waterflood. The Bennett Ranch Unit¹⁵¹ is located in the northeastern portion of the Wasson Field and produces from the San Andres formation at a depth of 4800 to 5600 ft. Currently (1996) the unit-wide average oil cut is 6%. CO₂ flooding was initiated in June 1995. The cost of implementing the project and the associated risks are considerably lower than in the Denver Unit project (see below) costs. The risks are lowered by:

1. Concentrating on the richest resources;
2. Minimizing the initial investment;

3. Staging the project to substantiate the response before committing major capital expenditures;
4. Optimizing the target interval of the transition zone.

The design and implementation study employed several scoping models, including a scaling spreadsheet based on dimensionless CO₂ recovery curves calibrated to the neighboring Denver Unit. This initial study indicated marginal performance and high up-front cost. To lower the cost a simulation study was conducted. Simulations provided the ability to 1) evaluate the co-development of different zones, 2) quantify the impact of CO₂ confinement, 3) evaluate the impact of layer heterogeneity 4) stage the project development 5) plan facilities and schedule well work. Simple scoping models cannot predict the co-development of different zones.

The WODCU¹⁵² is located along the eastern flank of the Wasson field in Yoakum County, Texas. Discovered in 1936, the WODCU produces from the Permian San Andres formation and has since been developed on a 20-acre five-spot pattern. In November 1984 Amoco Production Company initiated CO₂ injection in the WODCU. A 1:2 WAG ratio was initially authorized. Oil production has been increasing since inception. CO₂ production began about eight months after startup.

The Wasson San Andres Denver Unit¹⁵³⁻¹⁵⁹ is on the southeastern edge of the north basin platform in Gaines and Yoakam counties, Texas. The unit produces from a depth of 4700 to 5200 ft. The field has a gas cap and a nominal oil/water contact, which is a zone of increased water saturation. The EOR production from this unit has substantially exceeded the predictions. The CO₂ pilot was initiated in 1978. CO₂ injection was originally implemented with both a continuous CO₂ injection and WAG areas. Each method has its advantages and has led to the establishment of a Denver Unit WAG (DUWAG) injection process. CO₂ injection began in the WAG area in April 1983 and a year later in the continuous area.

The continuous area response was observed soon after injection began and within four years the oil cut had risen from a low of 14% to 31%. The Unit is developed on a nine-spot pattern in the continuous injection area. There is an areal anisotropic behavior

that creates a non-radial flood front response in the continuous zone. Wells located east-west of pattern injectors experience earlier EOR response. Wells located north-south of CO₂ injectors or diagonally to the pattern injector respond more slowly. CO₂ injectivity started at a level equivalent to pre-CO₂ water injectivity and rose slowly throughout the CO₂ injection cycle. There have been a few troubling instances of flowing wells and the formation of hydrates freezing at producer wellheads during nights or cold weather periods. In addition a number of wells have gassed out and had to be shut in.

Oil response in the WAG area was slower but the CO₂ production was also lower compared to the continuous injection areas. The WAG created a considerable challenge to maintain injection rates. The water cycle was especially affected by loss of injectivity. The 9-spot patterns were converted to a line drive pattern in 1988 and appear to have spread the desired injection volume among more injectors and the desired rates were attainable in the WAG area without exceeding fracture pressures. The WAG area had several factors that contributed to poorer EOR performance: 1) lower WAG injectivity, 2) out-of-zone injection losses, 3) structural continuity, and 4) waterflood induced fractures. The unit's patterns are closely monitored and WAG cycle lengths were extended from every six months to yearly.

The two types of CO₂ injection schemes shows the advantage of early response in continuous injection and the long-term flood manageability of the WAG process. Thus the DUWAG was suggested where four to six years of continuous CO₂ injection was followed by 1:1 WAG. Implementation of the DUWAG in the continuous area reduced gas production while oil and water production remained constant. Field evidence suggests approximately 30% injectivity reduction for water after gas injection. Additional work¹⁵⁶ would be:

1. Determining optimum WAG cycle length,
2. Best time to switch from continuous to WAG injection,
3. Optimum CO₂ slug size.

The South Wasson Clearfork Unit,¹⁶⁰ one of the first CO₂ injection projects, began in this formation in 1986 using a high WAG ratio of 8:1 and low HCPV slug of 8% and is

termed a "CO₂ augmented" waterflood. The augmented waterflood met expectations with an increase of 7% to the unit's production. A 2:1 WAG CO₂ was implemented in 1990 based on the encouraging results. Compared to the San Andres formation sitting above the Clearfork, the average porosity and permeability is considerably lower. The gross interval however is four to five times thicker and pay is more discontinuous. Infill drilling to 20-acre spacing increased the floodability from 28% to 50% for line drive wells and to 70% for the five-spot patterns. The ultimate secondary recovery increased from 4.2% to 12.4% of the OOIP. Like the Wasson San Andres counterpart, the SWCU appears to have a directional flow performance behavior. The water injectivity drop was less than 10% with the injection profiles for switching back and forth between gas and water remaining unchanged.

Slaughter Estate - The Slaughter Estate Unit¹⁶¹⁻¹⁶³ encompasses 5,752 acres in 20- and 40-acre five-spot and 160-acre chickenwire pattern developments. Production is from the San Andres formation with average net pay of 79 ft, average porosity of 12%, and an average permeability of 4.9 md.

An acid-gas pilot was developed and monitored in an undeveloped area of the Unit from 1972 to July 1984. Incremental oil due to tertiary oil recovery is attributed at 19.6% for the pilot. The WAG process resulted in reduced injectivity during the solvent injection phase of the pilot project, but oil-producing rates indicated the WAG process provided excellent areal sweep. Chase gas injectivity was favorable to waterflood injectivity. Predicted and actual peak tertiary oil production occurred at different times and is suggested to be caused by inaccurately defined heterogeneities. Miscible floods are more susceptible to reservoir heterogeneity than are waterfloods.¹⁶⁴ Water bottomhole injection pressures (BHIP) ranged from 2800 to 3100 psi. The gas injection rate was kept equal to the water injection rate to maintain a WAG ratio of 1:1. The gas injection pressures were about 100 psi below that of the BHIP of water.

Unit-wide CO₂ began in the Slaughter Estate Unit in December 1984. In modeling the SEU, both waterflood and early tertiary response was used. The contribution of high

k/ϕ layers can have significant effects on gas injection and response where in waterflood history matching these effects could be inconsequential. The initial WAG was a constant 1:2 with total slug of CO_2 of 30% HCPV. The WAG ratio was decreased during the flood, thus revealing that it is better to increase the WAG than to reduce it. In other words, it is desirable to start at a high gas rate and lower it as the flood progresses. The WAG ratio was decreased to 1:4 (increased GWR from 2:1 to 4:1) to accelerate rates. This could result in an increase of viscous fingering. The WAG ratio was changed to 1:0.75 in the southern portion of the Unit and 1:1.2 in the northern portion of the unit. This change was primarily due to oil price scenarios and the desire to reduce gas production.

The loss of water injectivity due to the WAG process is attributed to the higher final oil saturation to CO_2 reducing the solvent relative permeability and the maximum water relative permeability. The pilot had a larger reduction in injectivity due to BHIPs that were lower for the acid gas than for the water. The degree of stratification differs only slightly between the Slaughter Estate pilot and the unit. The Lorenz coefficient for the SEU is about 0.4.

The greatest loss of injectivity as a result of WAG happened in the Unit's most mature patterns, as indicated in Table 18. The injection profiles do not show significant differences between waterflooding and CO_2 -flooding. The retention of CO_2 is deemed good at 91%. The chicken-wire patterns are expected to respond slower.

Brent Formation North Sea - This particular EOR project is a first contact miscible methane injection project. The Brent formation^{96,99} is present in the majority of the North Sea fields and is a heterogeneous stratified sandstone. Production is from 3000 m (9840 ft) at 120°C (248°F). The sandstone is mixed-wet with larger pores tending to be oil-wet with residing oil and the small pores tending to be water-wet. Simulation of the Brent shows losses of injectivity due to stratification and gas trapping.

Mabee Field - The J.E. Mabee Field^{165,166} is located in Martin County, Texas and produces from the San Andres formation. In the evaluation of the Mabee field as a candidate

for EOR, specifically CO₂ miscible injection, the two related questions that have greeted most studies arose:

Could CO₂ be injected at reasonable rates and would the CO₂ and/or water injection rates after gas injection be reduced compared to pre-CO₂ injection water rates?

An injectivity field test was conducted. Two cycles of CO₂ and brine were injected and resulted in increased injectivity during the WAG cycles. Trends of increase injectivity with continued throughput were observed during both CO₂ injection cycles. Brine injectivity exhibited a gradually declining injectivity throughout the brine cycle. Extensive coreflood studies and computer simulations were conducted to study the injectivity phenomenon. These are reported on in various sections of this report.

Cedar Creek Anticline - The Cedar Creek Anticline^{96,167} is an 80-mile-long structure in eastern Montana and southwestern Dakota that contains at least a dozen carbonate reservoirs. The depth of production is approximately 9000 ft. Waterfloods have been conducted since the 1950s and 1960s with a watercut averaging 80% in 1988. An injectivity test was conducted in 1983 in the South Pines field to define the CO₂ flood potential of the Red River U4 interval of this structure. The test pressure measurements indicated that the CO₂ injectivity was approximately 14 times that of the preflood brine. S_{orw} is estimated at 40%. Corefloods exhibited low CO₂ injectivity behavior. The differences between the corefloods and the field injectivities are attributed to fluid/rock properties, the effective wellbore radius or skin and heterogeneity in the layering. The Cedar Creek rock appears to be more water-wet than the west Texas carbonates like the Wasson field.

McElroy Field - The McElroy¹⁶⁸⁻¹⁷² field produces from the intertidal and shallow shelf dolostones and siltstones of the Grayburg formation overlaying the San Andres formation evaporitic dolomites. The field is located in eastern and western portions of Crane and Upton counties respectively. The field has an areal extent of about 50 sq miles or over 30,000 acres. Production from the 275-ft thick Grayburg-San Andres dolomites is at depths of about 3000 to 4100 ft. Porosity is approximately 14% with a permeability range of 0.01 to 2,000 md. The Grayburg formation is very heterogeneous with a Dyk-

stra Parson coefficient of 0.91 to 0.987 and a Lorenz coefficient of 0.461 to 0.723 (0 indicates uniform permeability), with significant changes over short distances, mainly because the pores are plugged by anhydrite and gypsum. In addition the formation has some degree of natural fractures. The McElroy field is estimated to have 2.2 billion barrels OOIP. Primary and secondary recovery processes have been about 14.8% OOIP. A concentrated effort as to the in situ stresses in the reservoir was conducted to aid in realignment of wells to improve sweep efficiency. The McElroy field has a directional permeability trend as indicated by injection/production history. As a result of waterflood realignment reservoir pressures have increased and production has also increased.

Some wells in the McElroy field CO₂ pilot project experienced drastic losses in water injectivity of 80-85%, averaging about 60% of pre CO₂ water injection, whereas other wells did not during WAG CO₂ injection. Kamath et al¹⁷⁰ could not duplicate the injectivity losses in the laboratory.

Hwang and Ortiz¹⁷¹ investigated the geochemical characterization of the McElroy oil and discovered considerable evidence of asphaltene and asphaltic colloid deposition during CO₂ flooding. These depositions in the pores could cause blockage of the pore throats, possibly change the wettability, and serve to nucleate water-in-oil emulsions. Laboratory CO₂ corefloods, showed an increase in injectivity with time during the waterflood and a significant drop in injectivity as soon as the CO₂ WAG started for both the water cycle and CO₂ cycle. After the CO₂ pilot in the McElroy field, analysis of the produced oil showed over 50% reduction in the asphaltene content, indicating the occurrence of asphaltic precipitation in the reservoir. Hwang and Ortiz' study also showed that most of the heavy organic deposit near the CO₂ injection ports, suggesting that organic deposition in the field occurs near the injection wells rather than producing wells.

North Ward Estes CO₂ flood - Discovered in 1929 and encompassing about 39,000 acres in Ward and Winkler counties Texas, the North Ward Estes^{173,174} field is estimated to contain 1.1 billion barrels OOIP. Cumulative oil production by 1995 was approximately 338 million barrels or 30.7% OOIP. Production is from the Yates and Queen sandstones,

with the Yates being the predominant producing formation at approximately 2600 ft. The Queen formation lies below the Yates and is composed of similar sandstone/siltstone thin (<15 ft) lenticular sands with poor lateral continuity. The Queen is difficult to waterflood and is not considered a candidate for CO₂ flooding.

The Yates is divided into nine major sandstone/siltstone reservoirs separated by dense dolomite beds. A number of improved recovery projects were conducted since 1975, which included in-situ combustion, caustic flood pilots, polymer-injection profile modifications, pattern realignment and infill drilling. The infill drilling, pattern realignments and increased water injection projects were the most economically successful. Initial field development was on 20-acre spacing with more productive areas on 10-acre spacing. Waterflooding has been successful and has had a good areal sweep efficiency; however, vertical sweep efficiency was not as favorable due to permeability contrasts among the major sands with a Dykstra-Parsons coefficient of 0.85. Amott wettability tests on preserved cores was zero for all tests, suggesting that the Yates sands are water-wet.

Six sections were chosen for CO₂ flooding that had a cumulative oil production of 41.5% of OOIP for that area. The feasibility evaluation included extensive laboratory works, an injectivity test, and reservoir simulation study. The injectivity test consisted of injecting CO₂ for 50 days in a single well and showed a 20% increase over the water injection rate at the same bottomhole pressures. After injection of 30 MMscf (1.3% HCPV) of CO₂, the well was returned to water injection with no loss of injection. Eight percent tertiary oil recovery was expected with a WAG ratio of 1:1 and WAG size of 2.5% and a total CO₂ slug size of 38% HCPV.

CO₂ injection into the six sections commenced in April 1989 and after six years 21% HCPV CO₂ has been injected. Target water injection rates were difficult to achieve in some patterns, so these were placed on continuous gas injection, responding better to continuous CO₂ than to WAG. Initially the WAG process was based on time. In 1992 the flood was switched to volume-based WAG. A CO₂ slug (1.5% HCPV) could be injected in a one-month time frame but water took longer much of the time. This result was consistent with CO₂ injection being 20% higher than the water. The WAG ratio ranged

from 0.8:1 to 1.2:1. Two patterns are currently (1995) on continuous gas injection while 57 other patterns are on volumetric WAG process. Gross and net gas utilization is 15 and 7.1 Mscf/Bbl respectively. The North Ward Estes Field has shown up on the *Oil and Gas Journal's* "List of Completed, Terminated, Postponed and Delayed U.S. Projects," (April 1998).⁹¹

Sundown Slaughter Unit - The Texaco-operated Sundown Unit,¹⁷⁵⁻¹⁷⁷ in the Slaughter Field, Hockley County, Texas, produces from the San Andres formation and is one of many CO₂ floods currently operating in this vast field. Pattern development was typical west Texas chicken wire patterns that were changed to a pseudo-line drive, running almost perpendicular to the known production permeability and fracture propagation trend. Maintaining the injection pressure below the formation parting pressure would allow this pattern to be used without harming areal sweep. Other operators have also converted the chickenwire patterns to line drives.

The CO₂ flood, started January 1994, had been justified in 1990 by an analogy using dimensionless CO₂ flood performance curves based on a neighboring unit, the Mobil Mallet Unit. CO₂ flood simulation was performed later to improve forecast and optimize operations. Economic evaluations of this flood showed that the CO₂ process is not as sensitive to the WAG ratios as originally thought, being much more influenced by the price of oil than by the particular CO₂ injection scheme selected. Continuous injection was selected as the most economical injection scheme. This was based on offsetting operator's documentation of an increasing loss of injectivity after each WAG cycle. An injectivity test was conducted by injecting water into select wells after a large volume of CO₂ had been injected. The wells typically showed losses of 38 to 57 percent of their waterflood injectivity. Also, the retention of CO₂ is high in offset operators, which delays the need for WAG to control mobility immediately. A third concern is that WAG operations could cause blocking of residual oil. The plan is to use water or foams later when mobility control is warranted.

Wellman Unit - The Wellman Unit^{178,179} is a unique application of gravity-stable vertical CO₂ miscible flooding. The Wellman Unit is a limestone reef reservoir in the Wolfcamp reef complex in Terry County Texas. The reef complex has a water/oil contact at 6680 ft and has predominantly secondary porosity at 8.5% with an effective average core permeability of 110 md. Good vertical communication has been estimated from pressure tests to range from 500 to 1000 md. The OOIP is estimated at 126 MMSTB with primary and secondary recovery currently at 52.1% OOIP.

A vertical CO₂ miscible flood was implemented in mid-1983, with CO₂ injections reduced in 1986 due to oil prices. In November of 1989 the purchase rate of CO₂ was increased. CO₂ utilization is very good at 2.25 to 7.85 Mscf/Bbl. The ultimate oil recovery could be as high as 74.8% with the estimated tertiary oil recovery contributing as much as 16.7% OOIP.

Goldsmith San Andres Unit - A large CO₂ miscible pilot project was started in December 1996 in the Goldsmith San Andres Unit¹⁸⁰ (GSAU), Ector County, Texas. The pilot consists of nine inverted (center injector) five-spot 35.5 acre patterns encompassing 320 acres. A pilot was decided on because of uncertainties associated with CO₂ target oil saturation, the feasibility of re-entering abandoned wellbores, and overall CO₂ flood performance.

The Goldsmith field is one of the largest remaining San Andres reservoirs in the Permian Basin not under full-scale CO₂ flood. The GSAU was formed in 1952 with 18,240 acres, of which approximately 15,000 acres are considered productive. Cumulative oil recovery is reported at 240 MMBO with peak oil production in 1967 at 22,000 BPD and production declining by 1995 to 1650 BOPD at an oil cut of <4%. The Grayburg and Ellenburger formations have also been productive in the Goldsmith field, but the San Andres is productive throughout the Goldsmith field. The San Andres is an 1100-ft-thick dolomite structure but the Shoal open shelf is the major reservoir in this area and is 80-120 ft thick, existing at a depth of approximately 4200 ft. Average porosity and permeability are 11.6% and 32 md respectively. NMR logging showed S_{orw} ranged from 35-

49% with an average of 42%. Typical San Andres CO₂ floods range from 20-40%, with the average around 35-40%.

The flood design was heavily influenced by industry experience. For the GSAU the philosophy was to inject CO₂ continuously until the mobility control threshold was reached and then incorporate some form of mobility control. The initial design was to inject into the pilot a 10% HCPV of CO₂ followed by 30% HCPV slug of WAG CO₂ on a 1:1 ratio. Injection was to be maintained below parting pressure and 4-D seismic was to be used to help monitor the flood's progress. The simulation study incorporated geostatistics into its analysis and also compared a compositional simulator with a four-component miscible simulator. Miscible simulators are suitable for first-contact miscible processes and for multiple-contact miscible processes where miscibility occurs in a mixing zone that is small compared to the simulation grid. In this case the miscible simulator was reported to give results similar to a compositional simulator, thus saving computation time. The miscible simulator was chosen as the pilot simulation tool with the option to use the compositional model later when information from the pilot was obtained (CO₂ performance history match).

Between December 1996 and June 1998, 6.6 BCF of CO₂ was injected for a 13.5% HCPV. CO₂ retention is at about 90% and the pilot is producing about 200 BOPD compared to a baseline of 80 BOPD. Two wells experienced early CO₂ breakthrough that accounted for nearly half of the CO₂ production. One well was known to have problems during waterflooding. Dimensionless plots are being used to compare the GSAU performance to other CO₂ flood performance.

North Cross (Devonian) - Begun in 1972, the North Cross (Devonian) Unit^{181,182} CO₂ miscible flood was Shell Oil Company's first CO₂ flood. The Unit consists of 1155 acres in the Crossett Devonian field located in Crane and Upton counties, west Texas. The CO₂ flood was designed as a secondary rather than tertiary process due to low anticipated water injection. CO₂ recovery was expected to be 38% OOIP but the updated CO₂ ultimate recovery is expected at 22 MM barrels or approximately 42% OOIP and could go as

high as 43%, as the S_{orm} was indicated to be about 3%. Ultimate oil recovery could approach 63%. Additional infill drilling could increase the ultimate recovery.

Gas injectivity was significantly lower than initially predicted and was thought to be a result of near-wellbore damage, abnormally high pressures as various fluid banks developed, and formation of a low-mobility mixed zone.¹⁸¹ However, refinements in reservoir modeling and relative permeability data and further understanding of the miscible process allowed development of models incorporating gas-oil relative permeability adjustments while honoring absolute permeabilities. This allowed not only the production histories to be matched but also the injection rates. Thus the previously documented injectivity problems were a reflection of the modeling.

INJECTIVITY ABNORMALITIES

Injectivity Increases

Though not always the case, a number of the CO₂ floods have seen higher gas injection relative to pre-waterflood injection (see for example North Ward Estes, Mabee, and Cedar Creek Anticline). Also, some projects have had higher CO₂ injectivity after successive WAG cycles. CO₂ injectivity is much higher in reservoirs with crossflow when phase behavior and mixing is accounted for.¹⁸³

The CO₂ solubility in follow-up brine injection has been reported during WAG cycles that is enough to raise unsaturated brine injectivity three to five times the saturated brine injectivity. Increased brine injectivity during WAG cycles after the first slug of CO₂ has also been attributed to combined effects of¹⁶⁶:

1. High degree of heterogeneity
2. Crossflow
3. Oil viscosity reduction
4. Penetration of CO₂ into low permeability zones
5. Channeling of CO₂ through high permeability zones
6. Compressibility and redistribution of the reservoir pressure profile during shut-in periods prior to injection of brine, and

7. Solubility of CO₂ in injected brine near the wellbore.

The injectivity increase will not be as great where vertical permeability is lower, pay section is thicker, or the injection well is stimulated and production wells are not stimulated.¹⁶⁶ The effective wellbore radius or skin and heterogeneity in the layering reduce the influence of the oil bank resulting in higher injectivity.¹⁵⁵ The effects of low mobility in the tertiary oil bank and in the dispersive mixing zone near the CO₂ displacement front are more significant for a stimulated well because they pose a greater portion of the total flow resistance when resistance is lower near the well. In addition the fronts are moving with a velocity that varies with 1/R. The closer these banks are to the injection wellbore, the more effect the banks have on the activity at the injector.

Injectivity Reduction

Injectivity reduction after CO₂ injection has frequently occurred in the west Texas fields^{125,184} and also in the Brent formations after hydrocarbon gas injection in the North Sea area.^{96,99} The Levelland, Slaughter, and Wasson fields have all seen reduced injectivity during WAG process.¹⁵⁴

Schneider and Owens¹²⁵ studied 19 preserved cores from four oil-wet carbonate reservoirs to provide data in evaluating the cause of the loss of injection in a west Texas rich gas flood. Before the rich gas-water injection, water rates averaged 350 B/D and after gas injection, water injection rates averaged 100 B/D. The ratio of pre- to post-gas injection is similar in magnitude to the reduction observed in some relative permeability coreflood tests. Efforts to improve injectivity in the field following rich gas injection were largely unsuccessful.¹²⁴ There is no indication from Schneider and Owens regarding the skin condition of the wellbore other than well test data indicating that the reduced injectivity was not a wellbore or near-wellbore problem. Their analysis indicated that the problem extended some distance into the reservoir. The likely explanation suggested was that three-phase relative permeability effects caused the loss of injectivity as a result of bypassed or trapped oil. They proposed that the bypassed oil causes trapped gas saturation

to increase and lowers the attainable water saturation during water injection, resulting in lower mobility of brine.

The Levelland Unit CO₂ miscible pilot reported a 10% loss in CO₂ injectivity and a 50% loss of water injection versus the pre-gas water injection.¹⁸⁵ As a result of the loss of injection pressure cycles were observed in the composition observation well. Mobility was lower after CO₂ injection than before, indicating that mobility control was good and also suggesting that reduced injectivity is an in-depth phenomenon rather than a near-wellbore condition such as skin or high gas saturation around the injector.

One proposed explanation of reduced injectivity is related to rock wettability.^{94,154,184} Injectivity may be lower than anticipated relative to waterflood injectivity in intermediate-wet or oil-wet rock.^{100,101} The west Texas carbonates are mixed-wet, but predominately referred to as slightly oil-wet. The low CO₂ injectivity can be related to this mixed-wet nature, which causes low mobility in the formed or forming oil bank. But, by itself this low mobility oil bank cannot explain the reduced water injectivity.⁹⁴ Though not conclusive, intermediate wet cores became more water-wet after flooding with CO₂, based on relative permeability crossover characteristics before and after CO₂ injection.¹⁸⁴ Relative permeability data, floodout data, and hysteresis in the water permeability curves indicate the North Cowden Grayberg cores are intermediate- to water-wet and the Levelland cores tend to be intermediate- to oil-wet.¹⁸⁴ Wettability and its effects on injectivity as it is currently presented in the literature will be discussed more fully later in this report.

Reduction in water injectivity has also been attributed to the redistribution of the pressure profiles.^{94,96} Pressure cycling in heterogeneous reservoirs creates unstable conditions in zones of different oil saturations. In a water-wet reservoir the imbibition of water in a zone of high oil saturations is accelerated during the first half-cycle by a positive pressure gradient. In the second half-cycle, a pressure decrease causes the imbibed and retained water to displace a respective volume of oil into the higher permeability zone.⁹⁶ In a constant pressure system, injection of a solvent gas creates banks of different mobilities. The injected gas creates a pressure profile with a small pressure gradient near

the injector. Since the pressure gradient is small and water is less mobile than gas, and assuming that the injection rate is proportional to the local pressure gradient and injected fluid mobilities then the injection rate must decrease because reorientation takes much longer in a compressible fluid.⁹⁴

Stratification can have significant effects on the injectivity in a WAG project. The effective mobility is reduced not only in the highest permeability layers but also other noncommunicating layers. Thus, the higher permeability layer receives a higher fraction of gas and the resulting high compressibility and reorientation of the pressure profiles when the injected fluid is changed causes reduced injectivity.⁹⁴ In communicating layers, however, injectivity in the different high and low permeabilities zones or layers depends on WAG ratio and size of cycle. Increasing the injection rate and viscosity-to-gravity ratio reduces the difference of water and gas injectivities in the low and high permeability layers at the beginning of the WAG injection phase because the entrapment process is proportional in both layers. Increasing the gas bank in each cycle by decreasing the WAG ratio, e.g., from 2:1 to 1:1, improves the average injectivity ratio for both gas and water in the low permeability layer. Injection at relatively high rates traps gas but does not reduce water injectivity in the high permeability layer. Thus, the injectivity rate in the lower permeability zone continues to drop at the beginning of WAG.⁹⁶ Heterogeneity and stratification effects on injectivity are discussed in more detail below.

Phase behavior and the formation and mobility of the oil banks have been blamed for the loss of injectivity.^{96,154} Wasson Unit's oil banks dominate the normalized injectivity and cause brine injectivity to be less.⁹⁶ Wasson Denver Unit had a water injectivity loss of 30%.¹⁵⁷

Factors Affecting Injectivity/Wettability - During a reservoir's evolution, rock is laid down in a water environment and is thus initially water-wet. As hydrocarbons migrate through and/or accumulate in the rock's pore structure, oil will occupy the largest pores while the smaller pores remain filled by water because of insufficient capillary pressure.

¹⁸⁶ Various compounds in the oil will then chemically alter the surfaces of the pores.¹⁸⁷

The precise taxonomy of wettability is still lacking.¹⁸⁸ Buckley¹⁸⁹ categorized crude oil/brine/solid (COBR) interactions as polar interactions, surface precipitation, acid/base, and ion binding.¹⁹⁰ Anderson¹⁹¹ defines the terminology of different types of wettability.¹⁸⁶

1. Fully water-wet: A thin film of water prevents contact between the hydrocarbon and the grain surface.
2. Fully oil-wet: A thin oil film covers the rock matrix at all times.
3. Intermediate-wet: The oil/water interface makes a distinct contact angle with the matrix.
4. Fractionally wet: The internal rock surface consists of a random distribution of water-wet and oil-wet sections. This state of wettability can occur when the matrix is composed of different minerals that may differ in wetting characteristics or because of selective adsorption to random parts of the rock matrix.
5. Mixed-wet: The larger pores have become oil-wet owing to adsorption of hydrocarbons. The small pores have remained water-wet.

Key factors affecting the wettability state of a system (specifically in core analysis) are^{188,190,192}:

1. Aging: wettability achieved during aging depends on the saturation and distribution of the oil and brine phases and contact time.
2. Temperature: transitions towards water-wetness occur when the temperature is raised during the course of displacement.
3. Brine pH/composition: the salinity of connate and invading brines can have a major influence on wettability and oil recovery at reservoir temperatures; additionally, water-wetness and oil recovery by waterflooding increase with decrease in salinity.¹⁹⁰
4. Crude oil composition: changes in wettability induced by crude oil are related to changes in solvency of the crude oil with respect to its heavy components.
5. Connate water saturation.

Absolutely determining and reporting the wetting characteristics is not currently possible.¹⁹² Results from various labs concerning wettability are difficult to reconcile and understand. Variations in laboratory procedures and experimental materials make generalized conclusions about wettability almost impossible. Precise wettability conditions at the end of laboratory analysis are frequently difficult to deduce. In addition there have been concerns reported in the literature regarding the cross-correlation of the two main methods of determining the wettability of a rock, i.e., the Amott and USBM methods.¹⁸⁸ These two methods do not address pore scale wettability alteration issues¹⁸⁷ and only under certain conditions are the two methods expected to be equal.¹⁹³

Alteration in wettability are nonuniform with experimental evidence indicating that various components of the crude oil interact differently with various mineral substrates in the rock (e.g. quartz, feldspar, clays, etc.).¹⁹² The measurement of wettability alterations are difficult to determine and contact angle measurements do not adequately address this issue.¹⁸⁷ The adhesion test is suggested as a useful measurement^{187,194,195} of wettability alterations. However, the capillary force is difficult to control and the force applied to the nonwetting phase will establish the measurement.

The use of an atomic force microscope (AFM) is suggested as a direct way of measuring the critical capillary pressure for crude oils or the capillary pressure required to rupture brine films on mineral surfaces.¹⁸⁷ Capillary pressures determine the flow in a porous media and are related to the wettability of porous structures. Weak capillary forces are often operating in mixed-wet systems and are related to variation in contact angles. High capillary pressures imply a water-wet system whereas low values of critical capillary pressure imply large sections of the reservoir may be rendered mixed-wet because of brine film instability.¹⁸⁷ No experimental techniques are currently available to measure contact angle distributions in porous media and thus theoretical pore-scale simulators provide a tool to investigate the effects of varying wettability or contact angles at the pore level, accounting for non-uniform wettability alterations, partial film flow, trapping of wetting and nonwetting phases, and variations in advancing and receding contact angles.¹⁸⁸ Once water imbibition is over, a negative capillary pressure is required

via forced water drive for water to invade an oil-wet pore. Water cannot spontaneously imbibe into a water-wet pore if oil-wet pores encircle it. However, during forced water drive some of these oil-wet pores may become invaded by water and possibly resume the imbibition process into shielded water-wet pores.

Wettability has been shown to be a significant factor in the performance of WAG corefloods. Injectivity is related to the wettability of the reservoir. Rao, Girard, and Sayegh¹⁹⁶ showed that hydrocarbon miscible gas flooding could alter rock wettability in water-wet, intermediate-wet, and oil-wet systems. However, the wetting state is not the sole indicator of the type of mechanism controlling recovery.^{129,154,197} Most of these studies were conducted to study the effects of trapping, water shielding or blocking, relative permeability effects, and phase behavior or multiphase flow on the miscible process. These phenomena are also important to the injectivity problem¹⁰⁴ and will be discussed later.

The optimum WAG ratio is influenced by the wetting state of the rock. Gravity forces dominate water-wet tertiary floods while oil-wet tertiary floods are controlled by viscous fingering.¹⁹⁸ High WAG ratios have a large effect on oil recovery in water-wet rock.⁹⁴ High WAG ratios result in less oil recovery by extraction. Tertiary CO₂ floods controlled by viscous fingering had a maximum recovery at WAG ratio of about 1:1. Floods dominated by gravity tonguing showed maximum recovery with the continuous CO₂ slug process. The optimum WAG ratio in secondary floods was a function of the total CO₂ slug size.

Higher oil trapping due to wettability results from continuous-injection WAG processes with CO₂.⁹⁴ Significant oil trapping occurs in water-wet Berea rock, intermediate-wet rock has less trapping, and oil-wet Berea rocks have low oil trapping. Wettability alteration of Berea cores can be used to duplicate reservoir rock.^{98,197} Water injected simultaneously with CO₂ in water-wet rock traps significant amounts of oil, interferes with the development of miscibility and results in lower oil recovery; whereas, water injected simultaneously with CO₂ in oil-wet rock did not affect oil recovery and did not interfere with the development of miscibility.¹⁹² One should expect lower injectivity in gas floods

conducted in intermediate-wet rocks relative to waterflood injection.¹⁰⁰ Trapping is also discussed in detail in a separate section in this report.

Normally in strongly water-wet rock, water enters the smaller pores first owing to capillarity. In a mixed-wet rock most of the water will invade the larger pores first and then the smaller pores. The water flows into the pores that provide the least resistance to flow (i.e., larger pores), thereby competing with gas for the larger pores, and oil is less affected by the intermediate sized pores.¹⁹⁹ In the Brent Formation of the North Sea, larger pores tend to be oil-wet with residing oil and small pores tend to be water-wet.⁹⁶ Injected gas preferentially enters the high permeability layers, resulting in reduced water injection rate due to the three-phase effect and compressibility effects.⁹⁶

Tang and Morrow¹⁹⁰ suggest that reservoir wettability will change if the significant variables such as salinity and pH in the reservoir are changed. CO₂ forms a weak carbonic acid in water with a pH of 3.3-3.7¹⁰⁸; thus, changes in pH may affect wettability during CO₂ flooding. However, corefloods conducted by Potter¹⁸⁴ on preserved fresh-state cores taken from the west Texas Levelland Unit San Andres formation and the North Cowden Grayburg formation did not readily change wettability when flooded with oil and CO₂, but any change realized is towards more water-wet characteristics. Contrarily, CTVC (capillary tube visual cell) studies²⁰⁰ (using surrogate solvent and refined oil) and core studies in oil-wet, intermediate-wet and water-wet cores (using ethane as solvent and three reservoir oils)¹⁹⁶ show miscible gas flooding does induce wettability alterations. The CTVC studies show that miscible gasflood-induced wettability alterations occur and that water-wet surfaces become strongly oil-wet when in contact with swelling oil. The wettability changes are manifested in large changes in endpoint permeabilities with relatively lower change in endpoint water permeabilities. In intermediate wet and oil-wet systems the in-situ wettability alterations caused by solvent flooding had a significant positive effect on miscible flood performance. In some cases the impact of miscible flooding was the possible development or naturally occurring mixed-wettability conditions.¹⁹⁶

The distribution and flow of fluids in porous media is significantly impacted by the wetting properties of the pore walls.¹⁸⁷ Nonwetting fluids occupying larger pores will have larger relative permeabilities. Wettability is the most important cause of injectivity losses.¹⁵⁴ Treiber²⁰¹ concluded that 84% of the carbonates that he studied are not water-wet and that 90% of the west Texas/New Mexico carbonates were at least moderately oil-wet. Thus carbonates are more probably oil-wet or of mixed wettability.^{154,202} Water-wetness is characteristic of pure carbonate rock. Field-observed reduction in injectivity could be related to wettability. Mixed-wettability is suggested as a cause of low fluid mobility observed during the Denver Unit Wasson field CO₂ pilot.¹⁵⁴

Chemical Effects - CO₂ forms weak carbonic acid in water with a pH between 3.3 and 3.7 depending on the partial pressure of the CO₂. The carbonic acid readily reverts to CO₂ with increasing temperature and decreasing pressure.¹⁵⁷ Even at relatively low partial pressures, pH is reduced considerably.¹⁰⁸

Buckley¹⁹² has shown in controlled synthetic and fairly clean sandstone coreflood experiments that wettability can change with pH of the brine. A high pH alters synthetic cores toward more water-wet conditions while lower pHs have a tendency to alter cores and surfaces toward less water-wet conditions; however, pore coatings may control wetting alteration in natural porous media. The subject work also states that low ionic strength NaCl brines and asphaltic oil alters wetting to mixed-wet conditions.

There is considerable disagreement as to whether dissolution, precipitation and particle invasion or migration occurs during injection of CO₂ in WAG processes. It has been speculated that inorganic material dissolution occurs as the pressure declines while the flood front advances toward the producer. However, pre- and post-pilot core studies¹⁵³ and limited laboratory experimental studies¹⁵⁴ showed negligible dolomite dissolution occurring in the Wasson Denver Unit, or at least that this process had little effect on injectivity. Patel,¹⁵⁴ however, commented that the scope for a more comprehensive study of this mechanism exists. Contrarily, observations in other west Texas pilots and early work in the North Sea and Canadian sandstones suggested that CO₂ floods could have

significant effect on dissolution of the reservoir rock. Also, results have shown that oil hinders the rate of dissolution²⁰⁴ and thus more oil-wet reservoirs may not have high dissolution effects.

Literature on sandstone and carbonate diagenesis emphasizes the role of naturally occurring CO₂ in leaching processes. In the sandstone reservoirs of Pembina Cardium, Alberta, Canada, CO₂ corefloods initially showed a large drop in permeability, after which permeability rose steadily but did not regain its initial value.²⁰³ Microscopic (x-ray defraction and scanning electron microscope) examination indicated that fines had been released and had migrated toward pore throats, reducing permeability. The gradual rise in permeability noted in the experiments was attributed to mineral alterations by dissolution of calcite and siderite.

Laboratory coreflooding experiments under reservoir conditions on North Sea core material showed that dissolution could be a serious problem during CO₂ flooding.²⁰⁴ Unlike carbonate formations that are primarily made up of carbonates, sandstones contain small amounts of carbonaceous material primarily as cements consolidating the sand grains and creating the pore structure. A relatively small change in the pore framework due to dissolution could significantly affect the total permeability.

Thin section examinations of post-pilot core from the Wasson Denver Unit did not show evidence of dolomite dissolution, though anhydrite dissolution is seen but not statistically significant.¹⁵³ Carbonic acid is an effective agent in increasing the solubility of dolomite; thus, the lack of increase in porosity attributed to the possibility that a substantial pore volume contains CO₂ (not carbonic acid), so any trapped water will remain trapped in the smaller pores. The trapped water will come to equilibrium with the CO₂ and will form carbonic acid and dissolve the dolomite. This water will not be a mobile phase to any great extent during the CO₂ flood and thus no significant transport mechanism exists to remove the Ca⁺² and Mg⁺² and HCO₃⁻ ions. The brine postflood should form carbonic acid from trapped CO₂. There is evidence that this occurs, though sufficient pore volumes were not available to significantly increase total porosity.¹⁵³ How-

ever, continued cycling of CO₂ water, such as that which occurs in the WAG process , does not appear to have occurred in the pilot.

Anhydrite can be dissolved in brine undersaturated with CaSO₄ in the preflood. The presence of NaCl and CaCl₂ brine increases the solubility of anhydrite.¹⁸⁴ During the SACROC pilots, evidence obtained in falloff and pulse testing suggested that dissolution of dolomite occurred, and investigators postulated that precipitation of gypsum close to the injector²⁰⁵ was due to CO₂ injection. Tests run on North Cowden cores saw significant anhydrite dissolution due to brine composition, but nothing was mentioned about effects of CO₂ on dissolution of the dolomite cores. Use of MgCl₂ and MgSO₄ stabilized the water/rock reactions.¹⁸⁴

The Levelland Pilot¹⁸⁵ indicated possible effects from rock dissolution, evidenced by a dramatic increase in bicarbonate content with the total dissolved solids concentration greatly increasing in the water at both composition observation wells, indicating carbon dioxide dissolving in water and forming carbonic acid. Ion concentration was lower in the water from the injection wells than it was in the water from the observation wells, which suggests that the injected water was not in equilibrium with the formation. In addition, the authors suggest that the oil films of the intermediate oil-wet reservoir shielded the high salinity connate water from mixing with and being displaced by the lower salinity waterflood water. The injection of carbon dioxide could remove the oil film and expose connate water to the water cycles that follow.¹⁸⁵

Entrapment - Entrapment has been suggested as a cause of injectivity losses. Mechanisms found to affect trapping in miscible displacements at the laboratory scale are solvent diffusion, oil swelling, water saturation, and solvent contact time.

As a CO₂ flood progresses, the oil becomes increasingly heavy, suggesting that some oil is initially bypassed and later recovered by extraction.¹⁰⁴ Contrary to findings by other researchers, the amount of bypassing is not sensitive to flow rate or core length and miscibility develops over a short length (less than 12 in.).¹⁰⁴ Bypassing increases as the sol-

vent/oil viscosity ratio decreases. Major bypassing mechanisms are capillary-induced bypassing, dispersion, and macroscopic bypassing.¹⁰⁴

Experimental observations of flow rate and core length effects can give some indication of the relative importance of each type of bypassing:

1. Flow rate:

- Increasing with increase in recovery indicates capillary pressure effects dominate.
- Decrease in recovery with flow indicates dispersive bypassing or fingering is dominant.

2. Core length:

- Recovery independent of core length shows that either capillarity or dispersive bypassing dominates.

3. Viscosity:

- Viscous fingering and dispersive bypassing increase with oil viscosity.
- Capillarity bypassing is much weaker function of oil viscosity.

Dispersive bypassing results from a distribution of pore sizes, and occurs in single-phase flow. The distribution of pore radii gives rise to a distribution of path lengths and distribution of velocities. Mixing is not complete at the pore junctions with laminar velocity distribution in the pores, thus resulting in a broader distribution of residence time, especially at high flow rates and short contact time.

Capillary entrapment occurs when the oil saturation in a porous medium becomes low, and the oil-phase network loses its continuity. At this point, viscous and gravitational pressure gradients become insufficient to mobilize the remaining oil, which is trapped against capillary barriers within the porous medium.²⁰⁶ This bypassing phenomenon occurs in tertiary displacement since the solvent must displace water to mobilize and recover oil. The Laplace equation applied to an oil drop in a constriction through which water flowed accounts for most of the pressure drop due to frictional loss and wall effects.²⁰⁷ If viscous drag forces are large enough, the drop is mobilized and induces the snap-off process. Capillary entry pressure is higher in small pores and is effected by the wetting nature of the rock. In water-wet rock, solvent displaces water from the largest

pores first because their entry pressure is lower. In mixed-wet rock, the solvent will enter the smallest oil-wet pores first. Thus capillarity-induced bypassing may depend on rock wettability, but can occur in both mixed and water-wet rock. As viscous forces in the solvent bank increase relative to capillary forces the capillary-induced bypassing will be reduced.¹⁰⁴ The SWAG process, as suggested by van Lingen, Barzanji, and van Kruijsdijk,¹¹⁶ can be used to reduce the capillary entrapment of oil due to small-scale reservoir heterogeneities.

Macroscopic entrapment or fingering results from macroscopic-scale heterogeneities coupled with the mobility contrast between solvent and oil. This type of bypassing will depend on the dimensionless ratio of dispersion coefficient and velocity $D/\nu L$, D_t/D_l , and W/L where D_t and D_l are the transverse and axial dispersion coefficients respectively, L is the core length and W is the core width. Bypassing from fingering increases as the contact time decreases.

Trapped gas saturation is one of the key parameters in determining injectivity and displacement efficiency in a miscible CO_2 WAG injection project.¹⁴⁵ Trapped gas saturation influences water injectivity and the amount of diversion of water in the WAG process. There is extensive trapping of gas in the high permeability layers, which diverts water to lower permeability layers.¹⁹⁹ Gas trapping plays an important role in mobilizing and displacement of residual to waterflooding oil. The degree of oil saturation reduction and amount of gas trapping depends on the initial gas saturation prior to waterflooding, and the wettability of the rock.

A great preponderance of evidence in the literature shows that trapping behavior and relative permeability depend on the ratio of flow rate to interfacial tension (IFT).¹⁹⁹ Low IFTs occur near the miscible front in multiple contact miscible floods (MCMF). Capillary desaturation curves can give indications when IFT affects are important. Near the wellbore where pressure gradients are larger and also where the relative permeability curves approach the miscible limit, the IFT is larger.¹⁹⁹ Simultaneous trapping of oil and gas by water occurs at the tail of the multicontact miscible gas process because of the crossflow of oil.

Residual oil has little if any effect on trapped gas saturation.¹⁹⁹ Prudhoe Bay laboratory data indicate that trapped gas saturation is essentially independent of residual oil saturation.¹⁹⁹ This is contrary to what was evidenced in earlier flow studies by Schneider and Owens¹²⁵ conducted in 19 preserved west Texas reservoir cores. Schneider and Owens' study indicated that gas saturation increased due to oil bypassed by the solvent bank and trapped by subsequent water injection. This trapped oil and gas acted to lower the maximum attainable water saturation and resulted in lower mobility of subsequent water injection. Laboratory data supported field evidence of reduced water injectivity for the process.

Laboratory core floods on native state cores from the South Cowden CO₂ flood showed that trapped gas saturations in the main reservoir from 20-25% pore volume (PV) could develop during WAG cycles.¹⁴⁵ The South Cowden study also saw reduced water relative permeability, k_{rw} , after CO₂ injection and determined that the CO₂ relative permeabilities were lower than oil relative permeabilities at comparable water saturations.

Trapped residual oil is defined to exist as trapped disconnected phase surrounded by water and has been represented as¹⁰⁵:

$$S_t = S_{or} \left(\frac{S_w - S_{wc}}{1 - S_{or} - S_{wc}} \right)^\alpha \quad 20$$

where α is the trapping exponent and is equal to one if no trapping occurs.^{105,209} This phenomenon is also referred to as water shielding or water blocking. Factors governing trapping of residual oil are²⁰⁹

1. Water saturation
2. Wettability^{103,209}
3. Reservoir heterogeneity
4. Capillary forces
5. Dynamics of water solvent injection processes

Mobile water in the reservoir shields the in-place oil from being contacted by the injected solvent, resulting in poor solvent displacement and recovery efficiency.^{103,105,208-210} If the water saturation is reduced, part of this trapped oil may reconnect and make it more

accessible to solvent.²⁰⁸ Microscopic influences caused by heterogeneity in the porous media include increased mixing effects due to the tortuosity of the pore structure, longitudinal transverse dispersion of solvent, and mass transfer of solvent.^{209,210} Macroscopic influences such as channeling and crossflow are caused by permeability and wettability effects. Mobile water does not change the mass transfer process by which miscibility develops.²⁰⁹

The wetting conditions affect miscible displacement. Displacement by the nonwetting phase is affected by a highly mobile wetting phase saturation, where displacement by the wetting phase is not significantly effected.²⁰⁹ Injecting below the optimum WAG ratio produces a high concentration profile directly behind the oil bank and creates mobility or viscous instability, while injecting above this ratio improves the ratio and tends to improve or stabilize the process but substantially reduces displacement efficiency due to trapping and prolonged production. The optimum WAG ratio seems to be fairly insensitive to any assumed level of trapping of oil phase.²⁰⁹ The water solvent injection phase creates little trapping of oil but substantial trapping of solvent.

Trapping is significant in laboratory-scale corefloods, but rapidly decreases at field scale if larger water barriers (compared to water film thickness for laboratory scale) exist. Diffusion of solvent through water films and the resultant swelling of trapped oil and possibly the rupture of the water film can significantly affect the trapped oil saturation in coreflood experiments. The trapped oil saturation in solvent processes therefore has to be considered a function not only of the water saturation but also of the solvent contact time or the flooding state.²¹¹

Related to trapping is a phenomenon discussed in the literature as water shielding or water-blocking. The phenomenon is viewed in the reservoir as residual disconnected phase surrounded by water. Mobile water in the reservoir can "shield" the in-place oil from being contacted by injected solvent, resulting in poor solvent displacement efficiency. In wettability rock displacement tests, water injected simultaneously with CO₂ in water-wet rock trapped significant amounts of oil, interfering with the development of miscibility and resulting in lower recovery.¹⁰³ Water injected simultaneously with CO₂ in

oil-wet rock did not affect oil recovery and did not interfere with development of miscibility. Significant oil trapping was observed during simultaneous water/miscible solvent injection in water-wet rocks. However, for a mixed-wet system the amount of trapping was found to be a function of solvent throughput.²⁰⁸ In mixed-wet and oil-wet cores the amount of retained oil was found to be insignificant after prolonged water/solvent injection and was attributed to the dendritic (dead-end pore) oil in cores recovered by diffusion mechanisms.²⁰⁸

Water blocking measurements with refined oil over-predict the extent of water blocking for reservoir fluid displacements when wettability alteration occurs in various types of rocks including Berea, Alberta sandstone, and west Texas carbonate.²⁰⁰ Water blocking is significantly more severe for Berea sandstone than for reservoir materials, even strongly water-wet Alberta reservoir core. For high WAG injection ratios in Berea water-wet rock, shielding dominates the displacement process and the type of miscible process doesn't matter whether first contact or multiple contact miscible.²¹² The trapping function and oil and solvent mobility in Berea water-wet rock control water shielding. Water-blocking estimates for reservoirs should be based on measurements in reservoir cores using reservoir fluids.²¹²

In secondary CO₂ floods, local mixing caused by high water saturations reduce recovery only slightly because high mobility CO₂ mixes with and displaces the oil before injected water arrives and creates significant dendritic and trapped saturation.²¹⁰ Additionally, in tertiary CO₂ floods oil recovery is slowed and reduced by restricted local mixing because high water saturations cause significant dendritic and trapped fractions throughout the flood.

Relative Permeability - Relative permeability is an important petrophysical parameter, as well as a critical input parameter in predictive simulation of miscible floods. Relative permeability can include the effects of wetting characteristics, heterogeneity of the reservoir fluids and rock, and fluid saturations as well as other micro- and macro-influences. The importance of accurate determination of this parameter has been known since the

beginnings of improved and enhanced recovery processes. Research programs to collect relative permeabilities and attempts to model these parameters are replete in the literature. Interfacial tensions have been shown to be an important effect on relative permeability curves. The section on IFT discusses the effects of this phenomenon on relative permeability.

Early programs such as those by Schneider and Owens¹²⁵ used native state and re-stored state cores from four west Texas reservoirs. They recommended native state cores to obtain permeability data since the oil-wet native state cores retain their water repellency. The Pennsylvania State University steady-state relative permeability tests were conducted at room temperature. Part of Schneider and Owens' study involved water mobility reductions in the presence of three phases that could lead to potential reservoir water-injectivity problems. They concluded that the oil and gas saturations present act to lower the maximum attainable water saturation, resulting in reduced water mobility during subsequent periods of water injection.

Data from laboratory tertiary flooding studies at representative reservoir conditions are becoming available in the literature.²¹³ This data includes water/oil relative permeability when water saturation is decreasing, residual oil saturation in a miscible flood, and residual CO₂ saturations. These parameters influence predictions of oil recovery, CO₂ production, and breakthrough times. Large differences in CO₂ and oil relative permeabilities can generate large differences for predicted injectivity.²¹³ CO₂ relative permeabilities can be very small in representative west Texas carbonates; as much as 100 times smaller than the oil endpoint relative permeabilities.^{104,145,165} Reduced CO₂ permeability affects gas production and injectivity more than oil recovery. Defining R_k as the ratio of the CO₂ relative permeability endpoint divided by the oil relative permeability, Priestitis and Brugman²¹³ show that normalized injectivity (I_n) can be predicted if the solvent and oil endpoints are not assumed to be equal, see Table 18.

Defining CO₂ relative permeability as equal to the oil relative permeability will not predict the above behavior. Roper et. al.^{100,101} have shown through simulation that a sharp injectivity reduction at the start of the brine cycle can be associated with relative

permeability reduction near the well and then gradually experience an increasing injectivity trend throughout the rest of the cycle. The reason is suggested to be due to two-phase flow of gas and brine initially near the well; as the cycle proceeds the saturations and the relative permeabilities change.

Laboratory floods attempting to emulate the South Cowden CO₂ flood experienced appreciable water relative permeability reductions with values observed prior to CO₂ injection.¹⁴⁵ Corefloods conducted on native state cores showed that trapped gas saturations of 20-25% PV could develop in South Cowden reservoir rock during miscible CO₂ WAG operations. Gas relative permeability curves were then constructed to yield this magnitude of gas trapping in the simulation. In addition the data showed significant hysteresis effects in the water relative permeability between the drainage and imbibition curves. Irreducible water saturations after drainage cycles were 15-20% higher than the initial, connate water saturation.

Water hysteresis occurs after CO₂ injection. In the San Andres water hysteresis occurs at new and higher irreducible water saturations.²¹³ The injected CO₂ and oil bank develops a new minimum value of irreducible water saturation that does not go back to the original connate water saturation. Oil curve hysteresis studies showed that oil relative permeabilities measured during oilflood following a waterflood were larger than the oil relative permeabilities measured during the initial waterflood. These new oil relative permeabilities could be several times larger than the original. If hysteresis effects are not recognized or are ignored the aqueous and oil primary imbibition and drainage relative permeability curves differ.^{100,101} Hysteresis is seen in the water permeability curves but not the oil curves of Levelland core floods.¹⁸⁴

For the mixed-wet Prudhoe Bay reservoir, data show that $k_{ro} = f(S_o)$.¹⁹⁹ For water-wet rock the normal expectation is that $k_{ro} = f(S_{wg}, S_o)$ since gas and oil would compete for the same large pores and $k_{rw} = f(S_w)$. Residual oil saturation (ROS) is decreased by trapped gas and k_{rw} is diminished by the presence of gas—the result of the mixed-wet nature of Prudhoe Bay. When k_{ro} is a function of oil saturation only (i.e., $f(S_o)$) k_{rw} de-

creases in the presence of trapped gas, resulting in lower mobility than if k_{rw} was just a function of its own saturation, S_w . It is often assumed that k_{ro} increases in the presence of trapped gas in conventional three-phase relative permeability models.¹⁹⁹

For IWAG, oil relative permeabilities remain the same whether trapped gas was present or not. They appeared to be a function of oil saturation only. Water relative permeabilities were significantly lower with trapped gas present, indicating their dependence on both gas and water saturations.¹³⁸ Gas relative permeability was noted by Akin and Demiralto²¹⁴ to decrease with increase in flow rate for three-phase flow.

Correlations to predict three-phase relative permeability from two-phase data assume k_{rg} is a function of gas saturation and not dependent on the liquid phase displaced. In addition most relative permeability data is obtained at ambient conditions. Studies conducted by BP Research indicate that the assumption that gas relative permeability as a function of gas saturation alone is not valid for the reservoir sandstones studied.²¹⁵ The study, conducted under ambient and reservoir conditions measured the saturation distribution histories by gamma attenuation saturation monitoring with JBN analysis of the corefloods. The study suggests that unsteady state relative permeabilities obtained from displacement corefloods at ambient conditions provide similar information, though not equivalent to, data obtained at reservoir conditions. Dria, Pope, and Sepehrnoori²¹⁶ concluded, using dolomite cores and steady-state procedures, that the relative permeability of each phase is seen to depend on the saturation of that phase only.

Three-phase flow effects can have important influences on injectivity even when CO_2 is injected above its minimum miscibility point. Some researchers have suggested that the magnitude of the water relative permeability endpoint has only a small effect on WAG recovery.¹²² Gas relative permeabilities measured under three-phase flow conditions with CO_2 are much lower than with N_2 . This could result in lower total mobility and lower injectivity than would be predicted if nitrogen relative permeability data were used to calibrate the simulator.²¹⁶ Roper, Pope and Sepehrnoori^{100,101} studied the sensitivity of relative permeability effects and residual phase saturations on CO_2 injectivity using analytical and numerical compositional models and showed that the aqueous phase

endpoint is important both before and after CO₂ breakthrough (note that this study has limited discussion and simulation of brine injectivity or the WAG process). The analytical analysis does not take into account crossflow, dispersive mixing and three-phase flow. Roper's simulation analysis are reproduced in Fig. 30. Relative permeability endpoint effects on injectivity based on the analytical analysis reveal the following:

1. CO₂-rich phase k_r : Downstream from the solvent bank, the low mobility creates a series resistance to flow and limits the early time injectivity response; however, the solvent bank is a negligibly small part of the total resistance so early time injectivity is not sensitive to the CO₂ rich-phase endpoint. After CO₂ breakthrough, injectivity becomes an increasing function of the rich-phase endpoint and high permeability layers dominate injectivity response. In addition after CO₂ breakthrough a higher CO₂ rich-phase endpoint increases the aqueous saturation in the solvent bank and correspondingly causes a reduction in permeability of the CO₂ rich phase.
2. Oil phase endpoint: Injectivity is a strongly increasing function of the oil phase relative permeability within the tertiary oil bank. After CO₂ breakthrough, injectivity becomes a weakly decreasing function of the oil relative permeability endpoint because a higher endpoint increases the aqueous phase saturation in the solvent bank and causes a corresponding reduction in permeability of the CO₂ rich phase.
3. Aqueous phase endpoint: Injectivity is a decreasing function of the aqueous phase endpoint because the initial injectivity is a function of the aqueous mobility, which increases with an increasing aqueous phase relative endpoint. This initial aqueous mobility is the normalization factor in the denominator of the dimensionless injectivity ratio.

Relative permeability end-effects on CO₂ injectivity based on numerical analysis showed similar results as did the analytical analysis, although with two exceptions.^{100,101} These were that first, the analytical method was not sensitive to the CO₂-rich phase prior to CO₂ breakthrough and second, that dispersion and vertical communication had sub-

stantial effects on the CO₂ injectivity. The numerical compositional model indicates that injectivity is an increasing function for the first 1.75 HCPV. More crossflow produces higher injectivity because of increased transport of CO₂ in high-permeability layers near the injection face. Dispersion and vertical communication have extended the sensitivity of the early injectivity period to the oil phase endpoint in the oil bank. Injectivity prior to breakthrough is still an increasing function of oil phase relative permeability. However, sensitivity is reduced since the relative importance of the reduced mobility in the tertiary oil bank is not as great a limitation on injectivity as the low mobility in the dispersive mixing zone. The mobility in the mixing zone, which was not present in the analytical analysis, creates a greater resistance to flow and is less sensitive to oil phase relative permeability since the oil phase saturation is lower there.

Roper additionally studied the relative permeability curvatures using the analytical model to show that the non-aqueous phase (oil) relative permeability curvature applicable to the tertiary oil bank has the most important influence on the early injectivity, but little effect after CO₂ breakthrough. Note also in Fig. 30 that the oil and aqueous phase relative permeability endpoint diagrams and the relative permeability curvatures are almost inverses of each other. This exemplifies the antagonistic and synergistic complex behavior that coexists in the reservoir and shows why it is difficult to ascertain one individual parameter that has more influence over the injectivity phenomenon than any others. Shown also in Fig. 30 are the phase residual saturation effects to displacement and their consequences on injectivity of CO₂. This aspect is discussed below.

The distribution of the wetting and non-wetting phase fluids is a major factor in determining relative permeability characteristics. Non-wetting fluids occupying larger pores will have larger relative permeabilities.¹⁸⁷ To acquire a history match most simulations alter the relative permeability information significantly, as was done in the Sundown Unit of west Texas.¹⁷⁶ These extreme adjustments are made to compensate for more heterogeneity and are a faster and more convenient way to match waterfloods than to change geological models. Altering the relative permeability data also allows one to account for poorer sweep efficiency. Because of this, an excellent waterflood history

match obtained by altering the relative permeability does not guarantee a correct CO₂ flood forecast.

Adjusting the gas relative permeability curve could compensate for moderate differences in the reservoir heterogeneity. Drastically modifying the gas curve from expected values could create misleading results in timing and performances of the WAG and continuous CO₂ process.¹⁷⁷ Relative permeability and its effects is a study unto itself and again takes into account many petrophysical parameters. In order to confine the scope of the present study, this issue will not be discussed further. Additional comments on the effects of relative permeability on injectivity are related in the IFT section of the present study.

Saturation Effects - The nature of the WAG process causes the saturations to cycle and exacerbates the trapping occurrence. The volume of the trapped phase depends on the initial saturation prior to the flood.⁹⁹ High water saturation acts to reduce the amount of extraction that occurs in both water-wet and mixed rock.¹⁰⁴

Roper, Pope, and Sepehrnoori¹⁰⁰ in their analysis of the causes of tertiary injectivity abnormalities investigated saturation effects using an analytical model and a compositional numerical simulator. As discussed in the relative permeability section and illustrated in Fig. 30, the method of study they used compared an analytical model that made no allowance for dispersion or vertical communication with the compositional simulator that had considerable more complexity in the definition of the reservoir and fluids. They found that the analytical model yielded the following:

1. CO₂-rich phase residual saturation: The CO₂-rich phase residual saturation has a negligible influence on injectivity, even though it strongly influences the "water-CO₂" fractional flow curves. This is because all flow in the solvent bank takes place at high nonaqueous phase saturations and the water-oil fractional flow curve determines all downstream compositions. In other words the tangent lines to determine the leading and trailing compositions or saturations (i.e., what the authors refer to as compositions routes) are defined by the oil-water fractional flow curve

only. The water-solvent fractional flow curve has no effect on compositions in the tertiary oil bank, at least from the analytical model definition.

2. Oil phase residual saturation: CO₂ injectivity is an increasing function of the oil residual saturation to displacement by the aqueous phase before and after CO₂ breakthrough. High residual oil saturation reduces injectivity (at waterflood residual oil phase saturation) by decreasing the initial saturations and relative permeability of the aqueous phase. This results in high CO₂ injectivity relative to the reference injectivity (generally pre-CO₂ water injectivity). The higher oil saturation in the tertiary oil bank also contributes to increased total mobility for higher saturations of oil being displaced by water since the oil bank is smaller and the oil phase relative permeabilities are higher in the oil bank.
3. Aqueous phase residual saturation: The aqueous phase residual saturation affects early and late injectivity responses. Injectivity is a strongly decreasing function of the aqueous phase saturation prior to CO₂ breakthrough. Low values of the aqueous phase saturation increase mobility of the tertiary oil bank since the oil phase saturations will be higher. At CO₂ breakthrough the aqueous saturation alters the shape of the water/oil fractional flow curve and thereafter injectivity is an increasing function of aqueous phase saturation. This results in better sweep of low permeability layers during the early part of the displacement, improved sweep in low permeability area thus increasing injectivity, and reduced flow resistance in the low permeability layer.

The analytical solution discussed above showed that injectivity was not sensitive to the CO₂-phase residual saturation in the solvent bank. However, analysis by numerical compositional simulator predicts higher CO₂ injectivity early in the displacement for lower CO₂ residual saturations. Suggested reasons for this are increased mobility in the mixing and increased crossflow because of reduced pressure drop within the mixing zone in higher permeability layers. After CO₂ breakthrough, injectivity is a weakly decreasing function of CO₂-phase residual saturation. The authors reasoned that:

1. A lower value of saturation means increased total mobility ratio in the mixing zone
2. There is an increasingly unfavorable local mobility ratio where the multiphase mixture displaces compositions at the rear of the oil bank.
3. More oil is bypassed because of crossflow and instability
4. Increased bypassing of oil reduces the flow area available for CO₂ cycling through the reservoir.

A result from the UTCOMP compositional simulator¹⁰¹ showed that injectivity is very sensitive to the oil phase saturation where the saturation results from displacement by the aqueous phase. The analytical solution showed an increasing injectivity trend for higher residual saturation but the numerical solution shows a reversal in the presence of dispersion and vertical convective mixing. Higher oil-bank mobility is present in both the numerical and analytical solutions. Higher oil bank mobility reduces the driving force for crossflow, which dominates over other mechanisms and is responsible for causing injectivity to go from a decreasing function of this parameter to an increasing function prior to CO₂ breakthrough. Less crossflow improves sweep in high permeability layers. After breakthrough injectivity becomes an even more strongly increasing function of the oil phase saturation to displacement by the aqueous phase. The residual oil phase saturation to displacement by an aqueous phase is one of the most important petrophysical parameters regarding injectivity and the magnitude of its influence depends on the amount of crossflow.

The oil phase saturation to displacement by the CO₂-rich phase does not enter into the analytical model but the numerical model indicates it is one of the most significant influences on early time injectivity and one of the most important parameters in oil recovery predictions. In the presence of dispersion and vertical communication early time injectivity is an increasing function of the oil saturation displaced by the CO₂-rich phase. This is counter-intuitive since oil phase relative permeabilities at intermediate saturations are associated with higher residual saturation. A combination of several mechanisms combine and contribute to a larger oil saturation displaced by CO₂-rich phase:

1. More efficient oil bank transport
2. Increased CO₂-specific velocity in high permeability layer
3. Phase behavior effect
4. Oil viscosity in the low permeability layer
5. Instability effects

Higher value of oil phase residual saturation displaced by CO₂ increases the oil phase saturation in the mixing zone and in the solvent bank within the high permeability zone. This causes an increase in pressure drop in these zones and causes a subsequent decrease in the driving force for crossflow of oil in the tertiary oil bank from the high permeability zones to the low permeability layers. The increase in oil bank transport in the high permeability layer is more efficient and increases injectivity. Also, with less crossflow, of CO₂, the solvent bank in the high permeability layer travels faster relative to the oil bank in the low permeability layer. As a result a greater fraction of the length of the oil bank in the low-permeability layer is contacted by CO₂ and experiences oil viscosity reduction. This scenario can increase injectivity but as pointed out by the authors these are complex interactions and competing mechanisms can reverse both early and late time trends with other outcomes possible.¹⁰¹

The aqueous phase residual saturation sensitivity analysis shows that early injectivity prior to CO₂ breakthrough is a very strongly decreasing function of this parameter. Higher residual saturation reduces mobility in the dispersive mixing zone and complements the mobility reduction in the tertiary oil bank by lowering aqueous phase relative permeability at intermediate saturations. After CO₂ breakthrough sensitivity to this parameter is reduced. Reduction of mobility in the lower permeability layer also contributes to the relaxing of the sensitivity to this parameter after breakthrough. The presence of miscible residual oil saturation substantially reduces predicted oil recovery and reduces CO₂ relative permeability and should be applied together.²¹³

Heterogeneity, Anisotropy, and Stratification - Stratification may strongly influence the water/gas displacement process.⁹⁹ Horizontal fluid flow in vertically communicating po-

rous strata are influenced by flow perpendicular to the bulk flow caused by viscosity forces, capillarity forces, gravity forces, and dispersion.²¹⁷

Capillary crossflow can lead to significant improvement in vertical sweep. Typical oil reservoirs have a Dykstra-Parson coefficient of 0.6 to 0.8.¹⁸³ WAG recovery is more sensitive to reservoir heterogeneity than is waterflooding.²¹⁸ Unfavorable mobility miscible displacements lead to crossflow from the low permeability layer to an adjacent higher permeability layer and tend to reduce frontal advancement in the lower permeability layer.¹²²

Pizarro and Lake²¹⁹ studied the effect of heterogeneity on injectivity through geostatistical analysis and autocorrelation of the reservoir permeability distribution. Injectivity in a heterogeneous reservoir is a function of 10 parameters:

$$I = f(k_x, k_z, \mu, P_L, L, h_1, h_2, H, W, q)$$

where k is permeability in the x and z directions, μ is viscosity, P_L is pressure at well location x , L is the length of a rectangular reservoir, h_1 and h_2 represent the bottom and top of the perforation interval, H is the reservoir thickness, W is width of a rectangular reservoir, and q is flow rate.

In a three-dimensional, homogenous five-spot pattern, the dimensionless injectivity can be written as²¹⁹

$$I_D = \frac{q\mu}{2\pi k_h \left(P_L - \bar{P} \right)_{(x_w, y_w)}}$$

The effective aspect ratio $R_L = \frac{L}{H} \sqrt{\frac{k_z}{k_x}}$ has a strong influence on injectivity estimates.

Injectivity increases with R_L until vertical equilibrium is achieved. High injectivity indicates good vertical communication. Ignoring the effect of R_L injectivity is weakly dependent on pattern size.

Vertical conformance of WAG displacement is strongly influenced by conformance between zones. In a noncommunicating-layered system, vertical distribution of CO_2 is dominated by permeability contrasts.⁹⁹ Flow into each layer is essentially proportional to

the fraction of the overall system kh and is independent of WAG ratio. There is a tendency for more CO_2 to enter the high permeability zone with increasing WAG ratio.⁹⁴ Since the WAG behavior is cyclic, the most permeable layer responds most quickly and takes more fluid than its kh contribution. When water is injected it quickly displaces the highly mobile CO_2 and all the layers attain an effective mobility nearly equal to the initial value. The higher permeability layer(s) always respond first. WAG will reduce mobility not only in the high permeability layer but also in the low permeability layer and results in a larger amount of the CO_2 entering in the highest permeability layer.⁹⁴

The ratio of viscous to gravity forces is the prime variable for determining the efficiency of WAG injection and controls vertical conformance and displacement efficiency of the flood. Crossflow or convective mixing can substantially increase injectivity even in the presence of low vertical to horizontal permeability ratios.¹⁰⁰ Transport of CO_2 is enhanced significantly by the high-permeability layers establishing a highly conductive path parallel to the low-permeability layer. With crossflow, CO_2 is transported through the highly permeable layer and reaches downstream locations in the low permeability layer that without crossflow would have to flow through the low-permeability layer to reach the downstream locations. Thus crossflowing will increase injectivity of CO_2 . High permeability "thief" zones in the Mabee Field could be the cause of high injection rates.¹⁶⁶ Heterogeneous stratification causes physical dispersion, reduces channeling of CO_2 through the high permeability layer, and delays breakthrough.¹⁰⁰ This is attributed to permeability contrast and mobility ratio contrast caused by different growth rates in the mixing zone in regions of low oil saturation for CO_2 -swept regions in each layer, and is thus unfavorable.

Transport Considerations - A study using surfactants and a single capillary constriction investigated mass transfer at the pore level.²⁰⁰ The effects of mass transfer on oil trapped in pore throats indicate the mass transfer is sufficiently slow that equilibrium is not necessarily attained. This is contrary to a previous study by Raimondi and Torcaso²²¹ who concluded that mass transfer in porous media takes place at equilibrium conditions

and miscibility in a reservoir is attained instantly due to equilibrium. Though mass transfer through porous structures and packed beds have been studied for some time in other disciplines, these two studies are early attempts to apply the mechanisms of mass transfer to a petroleum recovery perspective.

More recent studies indicate that contact time on the development of miscibility has not been resolved.¹⁰⁴ Miscibility develops when light crude oil components mix with the solvent. Contact time can have a strong influence on flow performance. Some researchers suggest miscibility can require up to 32 ft or more. Others suggested that the core length is not a significant factor. Miscibility is most certainly dependent on the compositional makeup, and micro- or local heterogeneity in the cores probably lends to the discrepancy. Slim tube measurements give values of S_{orm} close to zero, which is far different from field and coreflood measurements that give considerably higher S_{orm} . In-situ emulsification is a natural consequence of systems that produce low IFT in the converging diverging porous media, and the Marangoni instability has been noted.²²⁰

As noted previously the mixing phenomena can significantly influence injectivity. At the reservoir scale physical dispersion can significantly reduce injectivity, though the oil bank mobility is not low and the longitudinal dispersion is scaled to reservoir conditions and the mixing zone is a small fraction of the porous media.¹⁰⁰ Thus analytical assumptions that dispersion and associated phase behavior can be neglected may not be justified. Injectivity is also reduced because dispersive mixing reduces channeling of CO_2 through high permeability layers and delays CO_2 breakthrough. Neglecting volume change of mixing and the presence of mixing zones, the associated mobility reductions are rendered increasingly more important in the high permeability layer as the displacement progresses and the solvent bank grows in proportion to the cumulative throughput in each layer. Injectivity is lower because a negative overall volume change upon mixing slows growth of the region invaded by low-viscosity CO_2 in both the low and high permeability layers.¹⁰⁰

Early investigators speculated that multiphase flow could significantly affect the injectivity of a field project.²²² Henry and Metcalf²²³ measured a slight injectivity drop across cores that had multiphase flow in CO_2 /oil systems. There is no clear experimental

evidence that multiphase behavior effects result in field-observed fluid mobilities. Patel, Christman and Gardner¹⁵⁴ concluded that phase behavior does not necessarily and by itself create injectivity decreases. Phase behavior effects have been shown to reduce fingering.¹⁸³ Accounting for phase behavior and mixing, CO₂ injectivity appears to be much higher for reservoirs with crossflow.

The CO₂-oil system is dynamic and forms multiple phases. Grigg and Siagian²²⁴ have shown that in low temperature CO₂ floods four phases can exist—three nonaqueous phases and a solid asphaltene phase. Additionally four liquid phases and a solid phase can co-exist in a CO₂ flood—an aqueous phase, liquid hydrocarbon, liquid carbon dioxide, and gaseous carbon dioxide. The system can move in and out of miscibility and thus dynamic phase behavior should be considered in modeling a system.^{100,225}

Interfacial Tension (IFT) - Unlike conventional gas and oil or water and oil, the flow behavior of low IFT fluids occurring in most EOR processes depend on IFT, viscosity, and flow rate as well as rock properties of pore distribution and wettability.^{226,227} The interfacial tension is one of the most important parameters in EOR process and more recently an increased effort in gas condensate reservoirs.²²⁸ The effect of low interfacial tension is to increase flow rates and lower the residual saturations, creating conditions for improved hydrocarbon recovery.²²⁹ The interfacial tension determines the curvature of the relative permeability curves. In a completely miscible process the IFT is zero and relative permeability is a linear function of the fluid saturation with slope of 1.²³⁰ This parameter is the most sensitive and the most easily modified in the capillary number. The capillary number is a function of velocity, viscosity and interfacial tension. Orders of magnitude change in the capillary number are normally required to result in significant decrease in residual oil saturation and with gas injection the IFT can be lowered significantly. In-situ mass transfer dictates the level of IFT reduction. Considerable decrease at relatively low cost is the benefit of miscible flooding. Pore size distribution also affects the IFT as IFT will dominate if pore throats are small.

Limited knowledge of the effects of low interfacial tension on relative permeability has been available since the 1950s; however, there has been little documented mathematical correlation other than empirical deductions between interfacial tension and gas-oil relative permeability.^{228,231} Typical early unsteady-state gas/oil relative permeability experiments did not span the range of interfacial tensions that would be present in a mass transfer-dominated system and are inadequate in assessing the mobility/IFT interaction.²²⁸ Thus the coupling of IFT, mobility, and pore size distribution has been omitted from many analyses.

More recent studies into the effects of IFT on relative permeability curves have been conducted and published. The most recent publications report on studies conducted on gas/liquid IFT effects on relative permeability in gas condensate reservoirs, but may be extended to near miscible/miscible EOR projects. In a miscible displacement process Harbert²²⁶ suggested that both water and oil relative permeability curves were found to shift upward, indicating the two phases interfere less with each other as IFT is reduced. In addition he suggested that flow tests on representative reservoir rock samples are necessary to describe low IFT relative permeability for field process performance calculation.

The relative permeability has been shown to vary for gas condensate fluids when the velocity changes at a fixed IFT or the velocity is fixed and the IFT is changed.^{230,232} Therefore numerous relative permeability curves are necessary to cover the range of flow rates and IFT values within a reservoirs different flow regimes. Henderson et. al.²³⁰ suggest that the capillary number could be used to correlate the gas relative permeability and the gas velocity and gas viscosity parameters. Further development in this concept is required. Fulcher, Ertakin and Stahl²³³ suggest that the capillary number is not important in correlating relative permeability and residual saturation, but the interfacial tension and viscosity individually affect the flow rate. They also observed that increasing the capillary number reduces hysteresis effects in the relative permeability curve. Below a surface tension of 2 mN/m the surface tension has a significant effect on relative permeability.²³³ One interesting phenomenon is that high IFT ultimately caused condensate relative per-

meability to decrease with increasing condensate saturation, and condensate immobile under gas injection could be recovered by water injection.²³²

McDougal, Salino, and Sorbie²³⁴ described gas-oil flow studies over a range of IFTs of three orders of magnitude (9.76mN/m to 0.019mN/m). The gas relative permeabilities curves showed a marked increase while very little change was observed in the oil curve with decreasing IFT. The gas curve becomes a linear function of gas saturation, as IFT tends to zero. Additionally these authors state that to predict *a priori* the directional trend of the relative permeability curves with varying IFT is very difficult since it is intrinsically linked to the viscosity ratio also. Therefore the effect of IFT upon relative permeability curves can only be understood by accounting for both the capillary number and the viscosity ratio's role in determining phase distributions during displacement.

Thomas et al.²²⁸ illustrate a method in which one may determine when one should be concerned more with controlling mobility and when IFT optimization is justified. Additionally, interactions between the pore size distribution, IFT, and viscosity will determine if miscibility is important to recovery. Low IFT is generally a necessary condition for efficient recovery from most reservoirs, but in many cases zero IFT is unnecessary unless the pore throat size distribution is extremely tight and the rock oil-wet. Spontaneous imbibition tests²²⁷ conducted on water-wet Berea sandstone with high oil saturation imbibed conventional water overnight. When low IFT fluids replaced the conventional fluids, neither the oil or brine phases were imbibed after one week.

Hanniff and Ali²²⁹ suggest that the capillary number plays an important role in controlling residual saturation and that changes in the capillary number are due almost entirely to changes in interfacial tension. But these authors also demonstrate the importance of gravitational forces compared to capillary forces and suggest that the Bond number is more appropriate in interpreting data. However, a gravity-dominated system does not exist when the interfacial tensions are below a critical value. Pope et al²³⁵ are of the opinion that it is not correct to model the relative permeabilities strictly or directly as a function of interfacial tension. These parameters should be modeled as a function of the

combined effects of pressure gradient, buoyancy, and capillary forces using a generalized form of the capillary number and Bond number into a trapping number.

The interfacial tension between water and CO₂ is high at low temperatures and pressures (e.g., about 70 mN/m at 25 C and 0.1MPa).²³⁶ As the temperature and pressure increases the interfacial tension declines asymptotically to about 20-27 mN/m, depending on the isotherm (see Fig. 31). At higher pressures the IFT is largely independent of pressure. This is attributed to the solubility increase of CO₂ in water with pressure. At higher pressures the free energy density of the CO₂ becomes more liquidlike and closer to that of water. Note that at low pressures (i.e., <3.5 MPa) the higher temperature isotherms have IFT values that are lower than lower temperature isotherms. As the pressure is increased, the IFT isotherms converge (crossover) at 2.5 to 3.5 MPa and thereafter the higher temperature isotherms have higher IFT values compared to lower temperature isotherms.

In the proximity (± 10 -20°C) of the critical point of CO₂, the interfacial tension decreases markedly and the surface tension of CO₂ is approached creating a dip or cusp in the IFT vs. pressure plot. At higher temperatures this dip or cusp is less of an effect eventually disappearing with temperature. This cusp is attributed to an increase in the excess adsorption due to attraction of CO₂ to the interface. The rise in interfacial tension after the dip with increasing pressure implies a desorption process.²³⁶ A very small amount of a third-phase intermediate in composition between the CO₂- and H₂O-rich phases is observed to occur at the minimum of the dip. The interfacial tension between the CO₂ and water system at high pressures is about 20-25 mN/m and is lower than that for water/hydrocarbon systems (i.e., for heptane and octane-water system the IFT is about 50 mN/m).²³⁷ This is attributed to the higher miscibility of CO₂ and water versus hydrocarbons and water.

Interfacial tensions of the ternary CO₂-water-alcohol mixtures are lower than the binary CO₂/water system (see Figs. 32-34). Though not shown directly methanol has the least effect on IFT reduction with progressively increasing effect to isopropyl alcohol (higher molecular weight alcohols). This leads to the possible use of surfactants to lower the interfacial tension between water and carbon dioxide.²³⁷ The interfacial tension be-

tween carbon dioxide and water can be lowered from ~20 mN/m to 2 mN/m with several surfactants. One surfactant, PFPE COONH_4^+ , has been shown to reduce the IFT to 0.8 mN/m with a critical microemulsion observed. This could allow a change in the relative permeability and increase injectivity during WAG. The solubility of polymers in CO_2 is generally low and is a function of the surface tension of the polymer and molecular weight of the polymer.²³⁸ However, the effects on the purpose of the flood (oil recovery) and the economics are not known.

CONCLUDING DISCUSSION

The number of EOR gas process projects continues to grow. This is especially true in the Permian Basin of west Texas and southeastern New Mexico. Other areas with large tertiary potential reserves such as California, Kansas, Oklahoma, Wyoming, Prudhoe Bay and Kuparuk in Alaska are implementing similar techniques to economically utilize and recover hydrocarbon resources. WAG processes continue to be a viable economic technique to enhance hydrocarbon recovery economics, but the technique requires considerable and appropriate refinements to beneficially implement.

Wetting characteristics of the reservoir rock appear to be the most controlling factor of the operating strategy for an EOR process. Water-wet conditions suggest continuous gas injection, while oil-wet conditions suggest WAG process with an optimum of equal or 1:1 velocity ratio. Mixed-wet conditions indicate that maximum recovery is a stronger function of slug size. Water-wet laboratory models indicate that gravity forces dominate, while in oil-wet tertiary floods, viscous fingering is a controlling factor.

Factors that influence WAG performance have been discussed regarding their individual contributions. Together these factors create complex interactions and can be synergistic or antagonistic contributors to the WAG performance. One of the reservoir management objectives of an EOR project is to secure optimum injectivity, sweep efficiency, and voidage relationship. The historical review of the literature shows increased injectivity abnormalities during the WAG process compared to pre-gas injection (i.e., water-flood water injection rates), and in general, a manifestation of multiphase injection and of

the reservoir characteristics. As a result, the industry has evolved techniques to alleviate or improve injectivity and/or recovery economics due to the WAG process. Industry experience or suggested management tools evolving are:

1. Initial scoping flood designs based on industry experience and dimensionless performance plots. These are valid assuming an infrastructure is present; later, when CO₂ flood data is available, a comprehensive simulation study can be completed to optimize the design. Under constraining economic conditions or areas of high uncertainties and/or complexity, comprehensive simulation studies need to be completed before implementation of any portion of the flood.
2. WAG tapering has been used to improve CO₂ utilization. Starting at high gas rates and reducing it over the flood life will give better results (i.e., increase WAG ratio). Some projects like the Texaco-operated Sundown Unit start with continuous gas injection, then later when mobility control is necessary, use foams and/or water. Unocal's HYBRID WAG and Shell's DUWAG are similar variations. Increasing the WAG is better than decreasing it during the life of the flood.
3. Volume-based WAG instead of time-based.
4. Realignment of wells or converting nine-spots and chicken wire patterns to line drive.
5. Use of horizontal gas injection wells can increase injection rates or improve voidage ratios.
6. Shorter and more frequent cycles help reduce large gas swings (see EVGSAU).
7. Increased WAG cycle lengths help alleviate effects of injectivity losses (see Wasson Denver Unit).
8. Use of foams, gels, and polymers.

These conclusions on factors affecting injectivity can be drawn from the literature:

1. Lower injectivity is not necessarily a near-wellbore effect.
2. Oil banks:
 - A. Low mobility in the tertiary oil bank significantly affects injectivity, especially for stimulated injection wells with non-stimulated producing wells.

- B. Effects of low mobility in the tertiary bank and in the dispersive zone are more significant for a stimulated well because they represent a greater portion of the total flow resistance when resistance is lower near the well.
 - C. The closer the banks are to the injection wells, the more effect the lower-mobility banks have on the activity at the injector. This is because the flood fronts move at a velocity that varies with $1/r$.
3. Salinity and pH:
- A. Salinity and pH may change reservoir wettability.
 - B. CO_2 is known to reduce the pH of the water.
 - C. Lower pHs have been suggested as causing less water-wet conditions. However, "pore coatings" may control wetting alterations in natural porous media.
4. Wettability:
- A. Wettability is the most important key parameter in injectivity reductions. Wetting properties of the pore wall impacts distribution of fluids and flow. Nonwetting fluids occupying larger pores will have larger relative permeabilities.
 - B. One series of west Texas corefloods has indicated minor, if any, changes on wettability from CO_2 flooding. Any changes seem to be toward water-wet conditions.
 - C. Another series of tests using CTVC cells and other cores showed that miscible gas flooding of oil-wet and intermediate-wet cores induced wettability alterations and resulted in less end-point water permeabilities.
 - D. Weak capillary pressures generally exist in mixed-wet systems, creating brine film instability and possibly causing water relative permeability differences in the reservoir.
 - E. In mixed-wet rocks, injected gas enters the high permeability layers, resulting in reduced water injection rate due to three-phase and compressibility effects.
 - F. Mixed-wettability is suggested as a cause of low fluid mobility.

- G. Carbonate reservoirs (specifically in west Texas) are more probably oil-wet or mixed-wet.
 - H. Injectivity losses due to rock wettability effects on miscible flooding and wettability need to be delineated.
5. There is considerable disagreement as to whether dissolution, precipitation and particle invasion/migration occurs during injection of CO₂ and/or the WAG process.
6. Fluid trapping or bypassing:
- A. Trapping and bypassing of gas is one of the key parameters in determining injectivity. The degree of oil saturation reduction and amount of gas trapping depends on the initial gas saturation prior to waterflooding and the wettability of the rock.
 - B. Bypassed or trapped oil causes three-phase relative permeability reductions resulting in loss of injectivity.
 - C. Trapping behavior and relative permeability depend on the ratio of flow rate to IFT. The IFT is larger near the wellbore, where pressure gradients are larger and where relative permeability curves approach the miscible limit.
 - D. There is a discrepancy in the literature as to the effect of residual oil saturation on the trapped gas saturation.
 - E. Mobile water in the reservoir may shield the in-place oil from being contacted by injected solvent. It has also been suggested that if the water saturation is reduced, part of the trapped oil may reconnect and makes it more accessible to solvent.
 - F. Optimum WAG ratio is fairly insensitive to any assumed level of trapping of oil phase.
 - G. Trapping appears to be more significant at the coreflood laboratory level and rapidly decreases at field scale.
 - H. Rupturing the water film can significantly affect the trapped oil.

- I. Trapped oil saturation in solvent processes has to be considered a function not only of the water saturation but also of the solvent contact time or the flooding state.
 - J. Trapping and water shielding of oil is significant in water-wet reservoirs.
 - K. Trapped gas creates significant hysteresis effects and reduces relative permeability to water, especially in mixed-wet and oil-wet reservoir.
7. Relative permeability effects.
- A. Oil and gas saturations present in a miscible flood act to lower the maximum attainable water saturation, resulting in reduced water mobility.
 - B. CO₂ relative permeability can be very small compared to oil endpoint relative permeability.
 - C. Relative permeabilities in miscible gas injection systems are dependent on the saturation of that phase only. In the Prudhoe Bay mixed-wet system, the oil relative permeability is a function of oil saturation only.
 - D. Gas relative permeability, as a function of gas saturation alone, may not be valid.
 - E. CO₂ injectivity is a decreasing function of the aqueous phase endpoint.
 - F. Injectivity prior to CO₂ breakthrough is a strongly decreasing function of aqueous phase residual saturation.
8. Directional permeability effects:
- A. Vertical heterogeneity and high k/ϕ layers can have significant effects on gas injectivity.
 - B. Crossflow or convective mixing can substantially increase CO₂ injectivity even in the presence of low vertical to horizontal permeability ratios.
 - C. The dispersive mixing zone has low mobility and can reduce CO₂ injectivity by augmenting total mobility and macroscopic oil bypassing, resulting from reservoir heterogeneity.
 - D. CO₂ injectivity is an increasing function of increased transport in high permeability layers near the injection face

9. Phase behavior:

- A. Mass transfer contact time and miscibility development rate still appears to be in contention in the literature.
- B. The IFT correlation of gas relative permeability by the capillary number is being debated in the literature.
- C. Increasing the capillary number has been suggested to reduce hysteresis effects in the relative permeability curve.
- D. Though low IFT is important for efficient recovery, zero IFT is unnecessary unless pore throat size is small.

FURTHER DIRECTIONS

Keeping in mind that laboratory injection studies alone cannot be considered perfect indicators of field scale injectivity during the WAG process, the following are suggested research directions:

- 1. Investigate high velocity effects around (WAG) injection wells and wettability effects, if any.
- 2. Investigate effects of miscible (CO_2) flooding on wettability and investigate mixed-wettability effects on mobility and WAG injectivity.
- 3. Investigate radial effects of flood banks, pressure redistribution, and crossflow effects on the WAG injectivity process. Most laboratory experiments use linear flooding techniques.
- 4. Investigate stratified crossflow (communicating and non-communicating permeability differences) and wettability and effect on WAG injectivity.
- 5. Investigate dissolution, precipitation and particle invasion/migration during CO_2 flooding in carbonates.
- 6. Determine the effect of residual oil saturation on trapped gas saturation and injectivity, and investigate saturation distribution and its effect on relative permeability for all phases. Is the gas relative permeability a function of its own saturation?
- 7. Investigate contact time, mass transfer and miscibility development.

8. Additional work needs to be accomplished with IFT and relative permeability curves, especially for gas/water (CO_2 /water) relative permeability. Can the gas/water IFT be reduced for greater water mobility and if so what effects will it have on the mobility control in a miscible flood?
9. Use of pore scale simulators is recommended to understand the effects of wettability (i.e., mixed-wettability) on miscible flooding and injectivity.

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Table 1. Properties of Composite Core

Composite core type	Center region				Annulus region			
	Type	K (md)	ϕ	Area (cm ²)	Type	k (md)	ϕ	Area (cm ²)
Isolated coaxial	Glass bead (90-120 μ m)	5000	0.42	1.27	fired Berea sandstone	500	0.23	7.58
Total length of isolated coaxial core = 6.7 cm								

Table 2. Summary of Isolated Composite Core Experiments

Test #	Description	Flow rate (cc/hr)	Ratio	Breakthrough in annulus region (PV)	Breakthrough in center region (PV)
1	CO ₂ displaced oil	16.00	1	N/A	0.26
2	CO ₂ -brine displaced oil	16.45	4:1	N/A	0.42
3	CO ₂ -foam displaced oil (0.05 wt% CD1045)	16.45	4:1	N/A	0.42
4	CO ₂ -foam displaced oil (0.25 wt% CD1045)	16.45	4:1	3.32	0.48
5	CO ₂ -foam displaced oil (0.025 wt% CD1045 & 0.5 wt% lignosulfonate)	16.45	4:1	0.75	0.35
6	CO ₂ -foam displaced oil (0.05 wt% CD1045 & 0.5 wt% lignosulfonate)	16.45	4:1	0.86	0.35
N/A: no breakthrough was observed					

Table 3. Sequence of Experiments in Adsorption Measurements

CD1045 alone	Preflush with lignosulfonate	Coinject with lignosulfonate
Brine 0.025 wt% CD1045	Brine 0.5 wt% lignosulfonate 0.025 wt% CD1045	Brine 0.025 wt% CD1045/0.5 wt% lignosulfonate
Brine 0.05 wt% CD1045	Brine 0.5 wt% lignosulfonate 0.05 wt% CD1045	Brine 0.05 wt% CD1045/0.5 wt% lignosulfonate
Brine 0.1 wt% CD1045	Brine 0.5 wt% lignosulfonate 0.1 wt% CD1045	Brine 0.05 wt% CD1045/0.5 wt% lignosulfonate

Table 4. Adsorption Results (lb/acre-ft)

Concentration (wt%)	CD1045 alone	Preflush with 0.5 wt% lignosulfonate	Coinject with 0.5 wt% lignosulfonate
0.025	707	490	707
0.05	1523	598	1033
0.1	2257	1388	1713

Table 5. Core Plug Brine Permeability

Depth	Q [cc/hr]	dP [psid]	L [cm]	k [md]	Porosity [%]	Pore vol [cc]
5304	97.6	18.6	5.93	11.2	15.7	10.57
5308	35.1	100	5.84	0.74	12.4	8.24
5319	0.8	133	5.38	0.012	7.8	4.76
5326	0.6	114	6.55	0.012	6.9	5.11
5370	0.08	>181	5.33	<0.0009	2.5	1.49
5465	0.2	>250	4.19	<0.0012	0.4	0.17
5555	2	103	5.36	0.038	5.7	3.43
5575	0.2	>250	4.19	<0.0012	1.3	0.59

Table 6. Acoustic Data

Depth [ft]	P-wave velocity [ft/sec]	DT [usec/ft]	Core PHI [%]	DTma [usec/ft]
5303	17449	57.31	14.4	45.0
5307	16713	59.83	16.0	45.5
5320	17862	55.98	12.4	45.6
5556	20181	49.55	6.7	44.6

Table 7. Definitions of the Fuzzy Sets A-4(x) to A4(x).

EL $A-4(x) = 1$, $x \leq -3500$ $= (-1/1000)x - 2.5$, $-2500 > x > -3500$ $= 0$, Elsewhere	EH $A4(x) = 1$, $x \geq 2000$ $= (1/200)x - 9$, $1800 \leq x < 2000$ $= 0$, Elsewhere
VL $A-3(x) = 1$, $-1350 > x > -1900$ $= (-1/800)x - 11/16$, $-550 > x > -1350$ $= (1/1100)x + 30/11$, $-1900 > x > -3000$ $= 0$, Elsewhere	VH $A3(x) = 1$, $1000 \leq x \leq 1500$ $= (1/500)x - 1$, $500 \leq x < 1000$ $= (-1/1050)x + 17/7$, $1500 < x \leq 2550$ $= 0$, Elsewhere
L $A-2(x) = 1$, $-450 > x > -550$ $= (-1/300)x - 1/2$, $-150 > x > -450$ $= (1/300)x + 17/6$, $-550 > x > -850$ $= 0$, Elsewhere	H $A2(x) = 1$, $400 \leq x \leq 500$ $= (1/250)x - 3/5$, $150 \leq x < 400$ $= (-1/250)x + 3$, $500 < x \leq 750$ $= 0$, Elsewhere
SL $A-1(x) = 1$, $-60 \leq x \leq -40$ $= (-1/40)x$, $-40 \leq x \leq 0$ $= (1/190)x + 25/19$, $-250 \leq x \leq -60$ $= 0$, Elsewhere	SH $A1(x) = 1$, $40 \leq x \leq 60$ $= (1/40)x$, $0 \leq x \leq 40$ $= (-1/190)x + 25/19$, $60 \leq x \leq 250$ $= 0$, Elsewhere
K $A0(x) = (-1/50)x + 1$, $0 < x \leq 50$ $= (1/50)x + 1$, $-50 \leq x \leq 0$ $= 0$, Elsewhere	

Table 8. Definitions of Rule Types

Well 8	Well 12 Fuzzy Set								
Fuzzy Set	EL	VL	L	SL	K	SH	H	VH	EH
EL	I	I	I	I8	I8	PI8	P	P	P
VL	I	I	I	I8	I8	PI8	P	P	P
L	I	I	I	I8	I8	PI8	P	P	P
SL	I12	I12	I12	I	I8	P	PD12	PD12	PD12
K	I12	I12	I12	I12	K	D12	D12	D12	D12
SH	PI12	PI12	PI12	P	D8	D	D12	D12	D12
H	P	P	P	PD8	D8	D8	D	D	D
VH	P	P	P	PD8	D8	D8	D	D	D
EH	P	P	P	PD8	D8	D8	D	D	D

Table 9. Fuzzy Control Actions.

Rule Type	Change Degree								
	GD	LD	D	SD	K	SI	I	LI	GI
I	GD 10	LD 10	D 10	SD 4					
	GD 15	LD 15	D 15	SD 10					
	GD 5	LD 5	D 5						
I8	GI 7	LI 7	I 7	SI 7					
	GI 3	LI 3	I 3	SI 3					
I12	LI 16	LI 16	I 16	SI 16					
	LI 22	LI 22	I 22	SI 22					
	LI 18	LI 18	I 18	SI 18					
D						SI 4	I 10	LI 10	GI 10
						SI 10	I 15	LI 15	GI 15
							I 5	LI 5	GI 5
D8						SI 7	I 7	LI 7	GI 7
						SI 3	I 3	LI 3	GI 3
D12						SD 16 or,	D 16 or,	LD 16 or,	LD 16 or,
						SD 22 or,	D 22 or,	LD 22 or,	LD 22 or,
						SD 18	D 18	LD 18	LD 18
P	LI 8	I 8 or,	SI 8 or,	I 8 or,		D 8 or,	SD 8 or,	D 8 or,	LD 8
	LD 12	D 12 or,	SD 12 or,	D 12 or,		I 12 or,	SI 12 or,	I 12 or,	LI 12
		I 2	I 2	I 2		D 2	D 2	D 2	
		I 3	I 3	I 3		D 3	D 3	D 3	
		I 9	I 9	I 9		D 9	D 9	D 9	
		D 11	D 11	D 11		I 11	I 11	I 11	
		I 14	I 14	I 14		D 14	D 14	D 14	
		D 17	D 17	D 17		I 17	I 17	I 17	
		I 20	I 20	I 20		D 20	D 20	D 20	
PD8						Do P and D8 for relevant column			
PD12						Do P and D12 for relevant column			
PI8	Do P and I8 for relevant column								
PI12	Do P and I12 for relevant column								

Table 10. Results and Comparison for Case I

Performance	147 Inputs			400 Inputs			Arbitrary Inputs		
	Either solution	Desired solution	Iterations	either solution	Desired solution	Iterations	either solution	desired solution	Iterations
NEQBF	57%	43%	8.3	100%	86%	8.7	20%	20%	32
NEQNF	100%	29%		100%	86%		100%	70%	
UMCGF	100%	29%	21	100%	71%	17	100%	20%	30

Table 11. Comparisons of Neural Prediction and Arbitrary Inputs for NEQBF Algorithm

Case	Number of Iterations		Ratio of Convergence	
	Neural Inputs	Arbitrary Inputs	Neural Inputs	Arbitrary Inputs
I	8	32	80%	20%
II	9	24	100%	50%
III	3	16	100%	80%
IV	5	22	100%	60%

Table 12. Results of Application I.

	No	$(q^{(0)}, p_w^{(0)})$	(q, p_w)	(f_1, f_2)	Iterations	Note
Neural	1	(72.91584, 5.95125)	(72.915840, 5.9512501)	(-0.0000038, 0.0000000)	2	
	2	(72.95940, 5.91592)	(71.018349, 6.0697698)	(-0.0000038, 0.0000000)	2	
	Average				2	
Arbitrary Inputs	1	(0, 0)				failed
	2	(30, 2.5)	(71.018356, 6.069768)	(-0.0000115, 0.0000153)	6	
	3	(60, 5)	(71.018356, 6.069769)	(0.00000382, 0.0000076)	4	
	4	(90, 7.5)	(71.018409, 6.0697765)	(0.00014877, 0.0000305)	3	
	5	(120, 10)	(71.018264, 6.069761)	(-0.0002098, -0.0000458)	17	
	Average iterations				8	

Table 13. Result of Neural-Network-Selected Initial Point

No	$X^{(0)}$	X	$F(X)$	Iterations
1	0.077795	0.111016549	-0.0000103936	2
2	0.076807	0.033971633	-0.0000002496	
3	0.076416	0.048875231	-0.0000003278	
4	0.076907	0.041877668	-0.0000014417	
5	0.076964	0.028118642	-0.0000016186	
6	0.084350	0.048468839	-0.0000033006	
7	0.824824	0.687671482	-0.0000529885	
8	0.591666	0.582063794	0.0000000000	

Table 14. Results of Arbitrary Initial Points.

No	$X^{(0)}$	X	Iterations
1	(0.0,0.0,0.0,0.0,0.0,0.0,0.0,0.0)	0.110965035 0.033968526 0.048878014 0.041881181 0.028120789 0.048472199 0.687714219 0.581917166	17
2	(0.0,0.0,0.0,0.0,0.0,0.0,0.0,1.0)	0.440398156 0.043199986 0.040500018 0.028400000 0.017400020 0.029000027 0.401100248 0.999999523	Failed
3	(0.0,0.0,0.0,0.0,0.0,0.0,0.0,0.5)	0.110973358 0.033969078 0.048877488 0.041880521 0.028120407 0.048471629 0.687707483 0.581944167	12
4	(1.0,1.0,1.0,1.0,1.0,1.0,1.0,0.0)	0.110889039 0.033963710 0.048882443 0.041886743 0.028124101 0.048477258 0.687776744 0.581686258	14
5	(1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0)	0.440400838 0.043201625 0.040501117 0.028401494 0.017401456 0.029001593 0.401100873 1.000000238	Failed
6	(1.0,1.0,1.0,1.0,1.0,1.0,1.0,0.5)	0.110973522 0.033969093 0.048877477 0.041880514 0.028120404 0.048471625 0.687707364 0.581944704	12
7	(0.5,0.5,0.5,0.5,0.5,0.5,0.5,0.0)	0.110942520 0.033969085 0.048875145 0.041875477 0.028118036 0.048470515 0.687749207 0.581999599	15
8	(0.5,0.5,0.5,0.5,0.5,0.5,0.5,1.0)	0.440400838 0.043200850 0.040500611 0.028400749 0.017400026 0.029000759 0.401100128 1.000000238	Failed
9	(0.5,0.5,0.5,0.5,0.5,0.5,0.5,0.5)	0.110973462 0.033969089 0.048877481 0.041880518 0.028120407 0.048471629 0.687707483 0.581944465	11
Average iterations			13.3

Table 15. Results of Random Initial Points

No	$X^{(0)}$	X	Iterations
1	0.7055475 0.5334240 0.5795186 0.2895625 0.3019480 0.7747401 0.0140176 0.7607236	0.1109310 0.0339677 0.0488785 0.0418821 0.0281217 0.0484741 0.6877448 0.5818890	9
2	0.8144900 0.7090379 0.0453527 0.4140327 0.8626193 0.7904800 0.3735362 0.9619532	0.4403466 0.0431973 0.0405018 0.0284025 0.0174018 0.0290032 0.4011468 0.9998956	Failed
3	0.8714458 0.0562369 0.9495566 0.3640187 0.5248684 0.7671117 0.0535045 0.5924582	0.1110195 0.0339718 0.0488751 0.0418775 0.0281185 0.0484687 0.6876690 0.5820717	4
4	0.4687001 0.2981654 0.6226967 0.6478212 0.2637929 0.2793421 0.8298016 0.8246021	0.1109922 0.0339707 0.0488759 0.0418787 0.0281195 0.0484703 0.6876926 0.5820258	10
5	0.5891630 0.9860932 0.9109643 0.2268660 0.6951155 0.9800032 0.2439314 0.5338731	0.1109931 0.0339703 0.0488764 0.0418792 0.0281196 0.0484704 0.6876911 0.5820001	5
6	0.1063697 0.9994146 0.6761759 0.0157039 0.5751838 0.1000522 0.1030226 0.7988844	0.1107325 0.0339605 0.0488844 0.0418907 0.0281283 0.0484859 0.6879177 0.5815760	10
7	0.2844803 0.0456491 0.2957729 0.3820107 0.3009705 0.9485711 0.9798294 0.4013743	0.1109600 0.0339685 0.0488778 0.0418808 0.0281207 0.0484723 0.6877199 0.5819232	7
8	0.2782800 0.1604415 0.1628216 0.6465871 0.4100732 0.4127668 0.7127305 0.3262062	0.1109910 0.0339703 0.0488762 0.0418788 0.0281194 0.0484703 0.6876940 0.5820087	13
9	0.6331789 0.2075611 0.1860135 0.5833590 0.0807146 0.4579715 0.9057298 0.2613683	0.1110613 0.0339758 0.0488700 0.0418670 0.0281146 0.0484641 0.6876442 0.5822967	22
10	0.7852122 0.3789026 0.2896650 0.9193771 0.6317424 0.6276420 0.4284564 0.0979738	0.1109800 0.0339698 0.0488766 0.0418792 0.0281198 0.0484709 0.6077039 0.4819840	Failed
Average iterations			10

Table 16. Comparison of Results

	Neural Prediction	ArbitraryInitials	RandomInitials
Success Ratio	100%	66.7%	80%
Iteration Number	2	13	10

Table 17. Location and Description of 23 WAG Injection Projects

WAG No.	Property	Reference	Location	Lithology	Formation	Discovery	waterflood started	EOR Started	Type of EOR	WAG ratio	injectivity problems
1	Cedar Creek	17335 17326	Montana	Dolomite carbonate		1950-60s		1983 Pilot			no
2	Dollarhide	35190	Andrews Co. Tx	carbonate	Devonian; Thirty one	1945	1962			0:1	
3	EVGSAU Ford	36710	Hobbs, NM	Dolomite	San Andres	1938	1980	1985	CO2 Mis.	2:1:4:1; 0.8:1	Yes
4	Geraline Goldsmith	20227		Sandstone	Delaware	1956	pilot 1969 field 1972	1981		0:1	
5	(Pilot)	48945	Ector Co. Tx.	dolomite carbonate	San Andres	1934	1954	1996	CO2 Mis.	1:1	
6	Jav/LEC	37780	Gulf of Mexico	dolomite		Jun-70	1974	1981	N2 Miscible		
7	Kunarak	16719 24930 28602 30726 35698	Central North Slope Alaska	intermediate wet sandstone		1969		IHC 1981 MHC 1988	IHC HC miscible	0.3:1:2:1	yes ?
8	Lost Soldier Tensleep	35191	Baird, Wyoming	sandstone	Tensleep	1916	1962	1989	MHC	1:1	yes
9	Mallet	36711	Cochran & Hockley Cos. Tx	anhydrite dolomite	San Andres	1940	1964	1991	CO2 Miscible	1:1 tapered	Yes; CO2 and water
10	McElroy Field	9716 20105 24873 39791	Crane & Upton Cos. Tx.	dolostone siltstone	Grayburg	1926	1960				yes
11	North Coles Levee	15499	Kern Co., Ca.	Sandstone		1938	1970	1981	Pilot		
12	North Cross Devonian	6390 24210	Crane & Upton Cos. Tx	trilobitic chert	Devonian	1944	1964 (residue gas)	1972		0:01	
13	North Ward Estes	19654 30729	Ward & Winkler Cos. Tx	Sandstone	Queen Yates	1929	1954	1989	CO2 miscible	1:1:2:1:1:2	higher gas
14	Prudhoe Bay	13600 19657 22398 26053 28397 28614 39628	North Slope Alaska	sandstone	Sadlerochit Sag River Shublik	1968 on line 1977	1984	1982 misc. 1987	HC miscible HC immiscible	3:1	
15	Seminole San Andres	36515		dolomite	San Andres	1936	1970	1985			
16	Simmonette	38824	Canada	carbonate Reef		1993		May-95	HCMF	4:1 optimum; 0.6:1 Actual	
17	Slaughter Estate	9796 22022 19375 26624	Texas	Dolomite	San Andres		1963	1984	CO2 miscible	2:1 3:1 to 4:1 1.2:1	Yes
18	South Cowden	35429 37470	Ector Co Texas	Shelf Carbonate	dolomites Queen	1948	1962		CO2 miscible		
19	South Wasson	24160	Yokham Co Dawson County, Texas	dolomite anhydrite	Clearfork	1940	1980	1986 augm wf 1990	CO2/misc	8:1	yes
20	Welch Unit	27676		dolomite	San Andres		1968	1993	CO2/Misc	1:1	
21	Sundown Slaughter	35189 35410	Hockley Co. Tx	Dolomite carbonate	San Andres	1937	1959	1994	CO2 misc.	1:1	Yes
22	Wasson Denver Unit	29116 27674 24644 24157 24156 17754 17335	Yokham and Gaines West Texas	Dolomite	San Andres	1936	1964	1984	CO2/Misc	2:1	yes
23	Wellman Unit	48948 22898		dolomite limestone	Wolfcamp	1950	1978	1983	CO2/misc gravity drainage		

Table 18. SEU Injectivity Losses by Pattern Maturity (from Ref. 162)

Pattern	CO ₂ loss %	Water loss %	Cycle Number
Total Unit	31	49	15
20 acre five-spot	40	57	16
160 acre chicken wire	16	49	9

Table 19. Injectivity as a Function of CO₂ and Oil Relative Permeability Endpoints
(from Ref.213)

R _k	I _n
1	2.9
0.1	1.5
0.01	1.1

Fig. 1. IFT (dense CO₂ and surfactants) vs. surfactant concentration.

Fig. 2. Decay of CO₂ foams with lignosulfonate.

Fig. 3. Decay of CO₂ foams with mixtures of 0.025 wt% surfactant CD1045 and lignosulfonate.

Fig. 4. Pressure profile and oil recovery history for the annulus low permeability region (0.025 wt% CD1045 was used as a foaming agent).

Fig. 5. Pressure profile and oil recovery history for the annulus low permeability region (0.05 wt% CD1045 and 0.5 wt% lignosulfonate were coinjected as a foaming agent).

Fig. 6. Total oil recovery history from an isolated composite core.

Fig. 7. Adsorption measurement apparatus.

Fig. 8. Adsorption isotherms for surfactant CD1045 and lignosulfonate.

Fig. 9. Adsorption results in different injection schemes.

Fig. 10. Adsorption breakthrough curves of tracer and lignosulfonate.

Fig. 11. Desorption breakthrough curves of tracer and lignosulfonate.

Fig. 12. Adsorption breakthrough curves of tracer and CD1045.

Fig. 13. Desorption breakthrough curves of tracer and CD1045.

Fig. 14. Average permeability and standard deviation for Lamunyon 50 over a 20 ft interval.

Fig. 15. Core plug 5304 Flood A.

Fig. 16. Core plug 5304 Flood B.

Fig. 17 Core plug 555 Flood B.

Fig. 18 Fractured core measurement.

Core Segment 232A, 5566 ft

PORT	kavg[md]
1	120.4
2	181.71
3	202.74
4	304.56
5	373.27
6	500
7	500
8	26.04

Matrix: $k=3.28 \pm 3.165$ md

Fig. 19. Fracture permeability measurement.

Fig. 20. MMP of Teague Blinebry dead oil.

Fig. 21. Typical net pay distribution in the Blinebry Formation.

Fig. 22. The layout of the wells in the history model with solid circles as producers and solid triangles as injectors. The CO₂-foam pilot area is an *inverted nine-spot* pattern with 8 producers and 1 injection well in the center.

Fig. 23. Well location map. Corresponding to Fig. 22, the unshaded wells are injection wells and the shaded ones are production wells. The history match problem is focused on the eight light shaded wells surrounding Well 13, while holding the productions of the dark shaded wells unchanged. The permeability of each block is assumed to be constant

Fig. 24. Definitions of the fuzzy sets $A-4(x)$ to $A4(x)$ of error versus membership grades.

Fig. 25. Control actions.

Fig. 26. The gradual approach of the simulated production towards the historical production data during the iterations of the simulator/controller for Well 8.

Fig. 27. The gradual approach of the simulated production towards the historical production data during the iterations of the simulator / controller for Well 12.

Fig. 28. MASTER Web, an NT-based loosely coupled parallel system built on an existing network/cluster of PCs.

Fig. 29. An oil well production system.

Sensitivity of injectivity to relative permeability endpoints

Sensitivity of injectivity to relative permeability curvature

Sensitivity of injectivity to residual phase saturation

Fig. 30. Parameter sensitivity on CO₂ injectivity (from Roper¹⁰¹).

Fig. 31. Interfacial tension isotherms for binary system water-carbon dioxide (from Chun and Wilkinson²³⁶).

Fig. 32. Comparison of different workers' interfacial tension measurements (where this work refers to Chun and Wilkinson²³⁶).

Fig. 33. Interfacial tension isotherms of 0.184 mf ethanol-water-carbon dioxide (from Chun and Wilkinson²³⁶).

Fig. 34. Interfacial tension of various aqueous ethanol-carbon dioxide solutions at 35C. (from Chun and Wilkinson²³⁶).