Reservoir Simulation of a Waterflood Pilot in the Naturally Fractured Spraberry Trend

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Abstract
The Spraberry Trend Area in west Texas presents unusual problems for both primary production and waterflooding. Primary production under solution gas drive recovered less than 10% of the oil in place. After more than 40 years of waterflooding the current oil recovery is still less than 12%. In order to improve the reservoir performance in the Spraberry Trend Area, our studies focused on characterization, modeling and simulation of the Humble Waterflood Pilot. A pilot model was constructed using a three-phase, three-dimensional, dual porosity simulator (ECLIPSE). Lack of understanding of two key issues are addressed, stress-sensitive permeability and rock wettability. These parameters appear to have a dominant effect in reservoir performance. This study emphasized detailed analysis of the stress-sensitive option used in the simulator by developing a numerical model of solid deformation and stress-pressure dependent permeability using a fully implicit finite-difference scheme. The numerical modeling of spontaneous and forced imbibition experiments using Spraberry core plugs were also conducted to investigate the wettability of the Spraberry matrix. These analyses may be helpful for understanding reservoir behavior and reducing uncertain parameters.
Several studies were conducted after successfully matching waterflood pilot performance. The waterflood pilot model was applied to run a series of sensitivity simulations for horizontal wells, well injectivity optimization, cyclic waterflooding, and other scenarios that could be useful to increase reservoir productivity. Based on results of waterflood pilot scenarios, this study may be able to provide guidelines for field development in the Spraberry Trend Area.

Introduction
Naturally fractured reservoirs behave in a significantly different manner from homogeneous reservoirs, due to the existence of two media, matrix and fractures. The matrix system is relatively tight with insignificant permeability. In contrast, fractures have high permeability but have significantly low porosity. The matrix system, which is the fluid storage element in the fractured reservoirs, feeds the fractures that are responsible for transport throughout the reservoir. The fractures not only enhance the overall permeability, but also create significant permeability anisotropy. Knowledge of the imbibition transfer, orientation and magnitude of fracture permeability anisotropy is important in developing and managing the reservoir. There is no established methodology available in the literature for developing a thin pay zone and complex, naturally fractured reservoir with low matrix permeability and an extensive set of fractures.

This paper describes a methodology developed for the characterization of the Spraberry field, a naturally fractured reservoir in west Texas through the interpretation of the Humble waterflood pilot performance. The Spraberry Trend Area was discovered in January 1949. The field is mainly composed of sandstone, shale, siltstone and limestone. The mask of the rock is divided into three distinct units: the Upper Spraberry, a sandy zone; the Middle Spraberry, a zone of shales and limestones; and the Lower Spraberry, another sandy zone. The individual beds rarely exceed 15 ft in thickness. Reservoir characterization demonstrated that the productive oil sands in the Upper Spraberry consist of two thin intervals, the 1U and 5U. The field covers about 400,000 acres and is a naturally fractured and solution gas drive reservoirs (Fig. 1). In addition to being one of the world’s largest fields in areal extent, the Spraberry Trend is considered one of the...
richest oil provinces in the world. However, the Spraberry field presents unusual problems for both primary and secondary recoveries. Primary recovery, which was dominated by capillary retention of oil in the matrix blocks, was less than 10% of the oil in place. Well productivity declined rapidly after the fracture system was depleted. Along with a rapid decline in well productivity, the gas-oil ratio increased rapidly, since primary recovery was dominated by solution gas drive. After a series of laboratory experiments, a waterflood pilot was started on March 8, 1955. The displacement of oil by waterflooding was proved successful in this pilot. From this result, large-scale waterflooding was initiated in the Spraberry Trend. After more than 40 years of waterflooding, the current oil recovery is still less than 12%. The reasons for its low productivity and disappointing waterflood performance have remained unexplained until now. Various hypotheses have been proposed to explain the poor performance of waterfloods. These hypotheses include: lack of pattern confinement and injection well density, incorrect well pattern alignment, fracture mineralization, lack of understanding the imbibition transfer mechanism and stress-sensitive permeability.

Two key issues that are the causes of low productivity were addressed in this study prior to modeling and simulation of the Humble Pilot; the stress-sensitive permeability and the imbibition mechanism. Through these two studies, the quality and quantity of the simulation data were enhanced. These studies also helped to conserve valuable data and information from the laboratory experiments. Information from geological and petrophysical analysis, core-log integration, fracture characterization, and extensive data available on a well-by-well basis were integrated to build the reservoir model and to simulate the waterflood pilot performance. When interpretation of this pilot is finished, an understanding will be gained that will aid in current plans for expanded process options. This pilot model can also be used in the future to simulate horizontal wells and CO₂ injection and combinations of these technologies.

Stress-Sensitive Rock Properties

Background. Fractures are the main fluid flow paths in naturally fractured reservoirs. Therefore, the productivity of naturally fractured reservoirs relies on the magnitude of fracture permeability. When pore pressure depletes due to excessive oil/gas production rates in highly stress-sensitive rock properties, the confining stresses on the reservoir rock increase, causing compaction of the rock. The interaction between fluid flow and rock volumetric deformation causes significant reduction in fracture permeability. This, in turn, may reduce the reservoir productivity. Evidence from several sources indicates that Spraberry wells are stress-sensitive. This evidence provided the primary motivation to study stress sensitivity in detail.

In modeling stress sensitivity, current conventional dual-porosity simulators treat permeability and porosity as a function of pore pressure and neglect the effect of rock deformation due to changing of the stress-state. Hence, productivity predictions obtained using conventional dual-porosity simulators in reservoirs with stress-sensitive permeability may be misleading. Therefore, a numerical model of a stress dual-porosity simulator was developed in this study to take into account the effect of solid deformation in naturally fractured reservoirs.

Numerical Modeling. Although naturally fractured reservoirs have been the subject of much research, few studies investigate the effect of solid deformation on the changes in fluid pressure. Because this topic is still being actively researched, uncertainties exist in the governing equation describing this process, as shown by the cited references. The governing equation used in this research is adopted from Chen and Teufel (1997), which is considered conceptually more consistent than other cited references.

The governing equation for fluid flow and the effect of solid deformation on the change of fluid pressure can be written as:

\[
\nabla \cdot \left( \frac{k_1}{\mu} \nabla p_1 \right) = b_{11} \frac{\partial p_1}{\partial t} + b_{12} \frac{\partial p_2}{\partial t} + b_{13} \frac{\partial (\nabla \cdot u)}{\partial t} - \Gamma (1)
\]

For the matrix system:

\[
\nabla \cdot \left( \frac{k_1}{\mu} \nabla p_2 \right) = b_{21} \frac{\partial p_1}{\partial t} + b_{22} \frac{\partial p_2}{\partial t} + b_{23} \frac{\partial (\nabla \cdot u)}{\partial t} + \Gamma (2)
\]

For the linear elastic of isotropic porous material:

\[
G \nabla^2 u_i + \frac{G}{l - 2v} \frac{\partial (\nabla \cdot u)}{\partial x_i} = \alpha_1 \frac{\partial p_1}{\partial x_i} + \alpha_2 \frac{\partial p_2}{\partial x_i} \quad \text{(3)}
\]

where the coefficients are represented by:

\[
\begin{align*}
b_{11} &= \Phi_1 c_{p1} + \Phi_* c_{p1} (\beta_1 - \alpha_1) \\
b_{12} &= \Phi_1 c_{p2} (\beta_2 - \alpha_2) \\
b_{13} &= \frac{\Phi_1 c_{p1}}{c_b} \\
b_{21} &= \Phi_2 c_{p2} (\beta_2 - \alpha_2) \\
b_{22} &= \frac{\Phi_2 c_{p2}}{c_b} \\
b_{23} &= \frac{\Phi_2 c_{p2}}{c_b} (c_p - c_p^*) \quad \text{(4)}
\end{align*}
\]

\[
\begin{align*}
c_{p1} &= \frac{\alpha c_b^*}{\Phi_1} \\
c_{p2} &= \frac{\alpha c_b^*}{\Phi_2} (c_p - c_p^*) \\
c_p &= \alpha c_b^* \\
\alpha_2 &= \alpha - \frac{\alpha c_b^*}{c_b} \\
\beta &= \beta - \frac{\Phi_1 c_{b}}{c_p} \\
\end{align*}
\]
For a two-dimensional case, equations 1, 2 and 3 are a set of a system of partial differential equations that lead to four equations in four unknowns: \( p_1, p_2, u_x, \) and \( u_y. \) The system was solved using a fully implicit finite difference scheme and the nonlinear system was solved by using a block Gauss-Seidel approach.

A comparison in performance between a commercial (conventional) dual porosity simulator and a stress dual porosity simulator has been made as shown in Fig. 2. With constant permeability-porosity case, both simulators give similar result in predicting the reservoir performance. However, in modeling stress-sensitive permeability, the conventional dual-porosity simulator under high production rates (> 100 bopd) is inadequate. Numerical results also showed that permeability reduction due to stress could significantly reduce well productivity in naturally fractured reservoirs.

**Imbibition Mechanism**

**Background.** Imbibition plays a very important role in oil recovery, during waterflooding in the naturally fractured Spraberry Area. Imbibition describes the rate of mass transfer between the rock and the fractures, which, in turn depends on wettability of the rock. Therefore, understanding the imbibition process is crucial. Two imbibition experiments were conducted; spontaneous and dynamic imbibition experiments.

**Spontaneous Imbibition Experiments.** Several studies have been conducted to simulate spontaneous imbibition experiments in a core plug using either analytical or numerical approaches. In this study, we were concerned primarily with capillary pressure as the only driving force in the spontaneous imbibition process. The experiments were conducted under reservoir condition using core plugs taken from the low-permeability Spraberry formation. Spraberry oil and synthetic Spraberry brine were used as wetting and non-wetting fluids. The work was performed to develop a mathematical model for matching the laboratory imbibition data. The matching data can be used to study the spontaneous imbibition process in detail and to investigate the effect of key variables on the imbibition rate.

**Numerical Modeling.** The mathematical model for that process was derived based on the following assumptions: gravity terms are negligible, capillary pressure is the only driving force where total velocity is zero, and fluid and rock are incompressible. The governing equation was obtained as follows:

\[
\nabla \cdot D(S_w) \frac{\partial S_w}{\partial x} = -\phi \frac{\partial S_w}{\partial t} \tag{4}
\]

where the non-linear capillary diffusion coefficient is defined as

\[
D(S_w) = \frac{k}{\mu_o} k_{ro} f_w \frac{\partial p_c}{\partial S_w} \tag{5}
\]

Because of the non-linear capillary diffusion coefficient, equation 4 must be solved by numerical methods. A fully implicit finite difference scheme was applied to solve equation 4. The core plug was totally immersed in water, so boundary conditions were set to be constant with 100% water saturation. Initial conditions are required to begin the time step sequence. In this study, initial conditions were specified equal to initial water saturation. In order to match the experimental data, the capillary pressure curve was only parameter to be altered.

**Figure 3** shows four experimental data and numerical solution matches for recovery against time, with low capillary pressure shown in **Fig. 4**. The low capillary pressure obtained from this study indicates that the Spraberry cores are weakly water-wet. This finding is also supported by the measurement of wettability index (average Amott index is 0.3). Sensitivity studies on imbibition rates for varying capillary pressure, oil and water relative permeability curves, oil and water viscosity, and initial water saturation were conducted. We found that the rate of imbibition is affected less by varying water relative permeability and water viscosity values.

However, the results from this study suggest that the static imbibition experiment may fail to predict the performance of waterflooding in naturally fractured reservoirs because of the following reasons: (i) the capillary pressure obtained from this study is very low compared to the experimental study that was used to generate capillary pressure, and (ii) the static imbibition ignores the viscous force.

Therefore, dynamic imbibition experiments were conducted using artificially fractured Spraberry core to illustrate the actual process of waterflooding in naturally fractured reservoirs. The work was proceeded by numerical modeling using a commercial black oil simulator (Eclipse) to generate matrix capillary pressure as a result of matching between experimental data and numerical solution.

**Dynamic Imbibition Experiments.** The dynamic imbibition concept was first introduced by Brownscombe and Dyes (1952). However, until now not many studies found in the literature on this subject, either experimental or theoretical. A coreflood experiment at low injection rate was performed under reservoir conditions. The fracture pattern on the core sample was generated along the long axis using a hydraulic cutter. The cut sections were put back together without polishing the cut surfaces and without spacers. The matrix face was sealed off to allow brine injection only through the fracture. The fractured core was inserted into the Hassler-type core holder. During the experiment, the oil-saturated core was flooded by injecting with constant injection rate at reservoir temperature and 500 psia confining pressure. The oil and brine produced were collected against time at the producing end of the fractured core until zero oil production rate was achieved.
Numerical Modeling.\textsuperscript{18} The rectangular grid block was used to overcome the difficulty of modeling the horizontal cylindrical core shape. Thus, the pore volume of rectangular shape was set equal to that of cylindrical shape.

Single porosity simulation was used instead of dual porosity simulation, because single porosity is more representative for modeling a single fracture from the artificially fractured core. However, this single porosity simulation has to be able to duplicate the behavior of dual porosity simulation, which has different properties for matrix and fracture media. Thus, the properties of fracture, such as porosity, permeability, relative permeability, and capillary pressure were added into the single porosity simulator.

Three layers were used in the model with the fracture layer between the matrix layers. In addition, 10 x 10 grid blocks were used in x and y directions. The fracture layer was injected at one end with constant low water injection rate. Oil and water were produced at the opposite end of the fracture layer. The rest of the boundary blocks had a specified no-flow boundary condition. As in the spontaneous imbibition modeling, relative permeability was fixed and the matrix capillary pressure curve was the only parameter adjusted to match the experimental data. Meanwhile, the fracture capillary pressure was set to be zero and a straight-line relative permeability was used in the fracture layer. Once numerical analysis results satisfactorily matched the experimental data, then the value of the matrix capillary pressure obtained was used as a verification of the matrix capillary pressure input of the Humble Pilot simulation.

The best matches between experimental data and numerical solutions (only cumulative water production and cumulative oil production are presented) can be seen in the Figs. 5 and 6. The matrix capillary pressure obtained from this study is in good agreement with that obtained from static equilibrium experiments (Guo et al.\textsuperscript{19}), as shown in Fig. 7.

Analysis of these two issues, stress-sensitive permeability and imbibition mechanism, appears to be helpful for understanding the reservoir behavior and enhancing the quality and quantity of the simulation data.

Modeling and Simulation

Beside the information obtained from the above study, the information from geological and petrophysical analysis of reservoir cores, core-log integration analysis, fracture characterization, well test analysis and extensive data sets available on a well-by-well basis, allows us to apply modern simulation techniques to evaluate the performance of this 40-year-old pilot.

The Spraberry Trend was proven productive in February 1949, producing predominantly two thin intervals, the 1U and 5U, in the Upper Spraberry (Fig. 8).\textsuperscript{20,21} The Upper Spraberry, at an average depth of 7000 ft, has a gross thickness of approximately 220 ft and is composed of six stacked units (1U-6U). The individual beds rarely exceed 15 ft in thickness. Core analysis and well logging showed that the reservoir rock is characterized by both low porosity and low permeability. Matrix permeabilities are on the order of 1 md or less with porosities ranging from 6 to 14 %. The pay zones are cut by an extensive system of vertical fractures as shown in Fig. 8. The values of matrix permeability would not be significant without a system of interconnected vertical fractures that allow oil to flow from the matrix through the fractures and to the production wells. Most of the oil is stored in the matrix, since fracture porosity is on the order of 1% or less.

The fracture orientation was obtained by a number of well tests, including pulse and interference tests, buildup and fall off tests, and interwell tracer tests. It varies from area to area from N36°E to N76°E; however in general, the direction is approximately N50°E, as shown in Fig. 8. Further measurements were conducted recently by coring the Upper Spraberry 1U and 5U sands horizontally and performing tracer slugs on the Midkiff Unit in the Spraberry reservoir.\textsuperscript{22} Approximately 400 ft of horizontal core was taken from the two main pay sections. Three distinct natural fracture orientations are present in these horizontal cores, trending approximately NNE, NE, and ENE.\textsuperscript{23} Forty-six core samples taken from 1U show that the average fracture trend is in N42°E. Fifty-seven core samples taken from 5U show that two fracture trends are present, with the average fracture trends are 32°NNE and 80°NNE, respectively, as shown in Fig. 8. Four different tracer slugs were injected in four different injection wells. The surrounding production wells were monitored for a period of 183 days following tracer injection. Two fracture systems were identified, a primary fracture system oriented at approximately N38°E and a secondary fracture system oriented in an east-west direction.

The magnitude of permeability anisotropy between on-trend and off-trend varies from about 6:1 to 144:1 or higher.\textsuperscript{24} The effective permeability of the reservoir as determined by pressure build-up tests ranged from 2 to 180 mD.\textsuperscript{25}

Fracture spacing is the other important quantitative fracture system parameter that is necessary to predict fracture porosity and permeability in a reservoir. Fracture spacing can be directly quantified and it does not change when the reservoir is perturbed. Variation in fracture spacing can have a dramatic effect on fracture permeability. The horizontal cores show that the average fracture spacing in 1U sand is 3.17 ft, while in 5U sand it is 2.7 ft (Fig. 8).

Based on that information, the reservoir model for the Humble Pilot area (Fig. 9) was developed using three-phase, 3-D and dual porosity options in Eclipse. Characterization of the Humble Pilot and corresponding input were included in the reservoir model. The dual porosity model was used, since the Spraberry formation is very tight, so no significant fluid flow in the matrix can be assumed. The main flow in the reservoir occurs through the exchange of fluid from the
matrix to the fractures and from the fractures towards the production wells.

The grid dimension is 22x18 with 396 grid blocks in the horizontal direction and three grid blocks in the vertical direction. A total number of 1188 grid blocks were used to simulate the pilot. The total number of grid blocks becomes twice that of a single porosity realization, since the simulator generates one set of grid blocks for matrix parameters and one set for the fracture parameters. The wells and all layers were aligned parallel with the major fracture system with an orientation of N50°E. Figure 10 shows the grid model for the five-spot pattern after orientation with the major fracture system. The virgin reservoir properties are shown in Table - 1. The reservoir fluid analysis report was conducted by Magnolia Petroleum Co. as displayed in Table - 2.

The fluid samples were recombined and flashed to reservoir conditions at a temperature of 140°F. It was found that the saturation pressure was 1840 psia, 460 psia below the estimated original reservoir pressure of 2300 psi.

The two main zones, the 1U and 5U, were modeled with one large intervening shale layer. It was assumed that there was no vertical communication in the matrix and fracture between the two different sand zones, by setting the transmissibilities of matrix and fracture in the intervening shale to be zero. This assumption agrees with recent horizontal core analysis.

Since regional fractures are primarily oriented in one direction, the on-trend fracture permeability is set to be different from the off-trend fracture permeability. The ratio of fracture permeability is 15:0.25. The matrix permeability is set to be 0.02 md. The difference between off-trend fracture permeability and matrix permeability is taken into account for cross fractures in the model.

The five-spot with one producer (Sh. B-9) and four injectors (Sh. B-2, Sh. B-4, Sh. B-6 and Sh. B-10) were modeled in the simulation. Straight lines connecting the four injection wells confined the 80-acre pilot area.

In addition to the five-spot wells, five observation wells: Sh. B-1, Sh. B-5, Sh. B-7, Sh. B-11, T-1, A-4 and Sh. B-8, were included to provide information on the changes in reservoir pressure and production rates. These wells might help in tracing the response of the flood outside the pattern.

In order to match the observed data from the middle producer, Sh. B-9, sensitivity cases were performed to evaluate ranges of behavior for different values to help assess the impact of major uncertainties on predicted performances.

A fracture spacing of 2.86 ft was used to history-match the observed field data performance. Decreasing the fracture spacing increases the shape factor value; hence, the transmissibility from matrix to fracture increases and therefore, the oil production rate increases.

Reservoir permeability was much greater in the major fracture trend than in the minor direction. A fracture permeability ratio of 15:0.25 between major (Kmf) and minor permeabilities (Kmt) and the matrix permeability of 0.02 md were used. We input different values for matrix and minor fracture permeabilities to account for cross-fractures. Water production rate increases with an increase in the minor fracture permeability, while increasing major permeability increases the oil rate.

The relative permeability used in this study is shown in Fig. 11. It is very difficult to accurately measure fracture permeability curves for a reservoir. The assumption for this curve is that both phases are equally mobile for the entire range of saturations for the fractures. It was observed that alteration of relative permeability curves in the fracture system does not significantly change the results.

A fracture porosity of 0.1% was used in the model. Using a fracture porosity 1.0%, not much water was produced because most of the water stayed in the fracture rock instead of flowing to the well. The matrix porosity was kept constant at 10%. Increasing matrix porosity increases oil in the matrix block, and therefore, oil recovery.

The major fracture direction is oriented approximately N50°E. Two additional simulations were conducted to investigate the effects of rotation of the major fracture orientation. The orientations simulated were N60°E and N85°E. Both these simulations resulted in too-high water production in the middle producer, since the well at these orientations was aligned with east and west water injectors.

After those sensitivities studies, an attempt was made to match the observed data for the middle producer, Sh. B-9. The numerical results shows good agreement with observed data, as shown in Figs. 12 through 15, using the parameters listed in Tables 3 and 4. The trend of oil and gas rates is similar because straight-line relative permeability curves in the fracture were used. The peak in the gas production rate observed in the field upon initiation of water injection is difficult to obtain in the numerical results. Several efforts were conducted to match that peak but it seems impossible to match the very high gas production rates. Although the gas peak cannot be matched, most of that rate shows good matches with numerical results.

The bottomhole pressure for the middle producer was strongly dependent on the rates of surrounding observation wells and the ratio of fracture permeability. Therefore, the ratio of fracture permeability was altered to match production and pressure histories. The pressure-sensitive option was also applied to model stress-sensitive permeability. This option was used as an additional parameter to match the simulated bottomhole pressure. The use of this option is valid due to low production rate of Humble wells.

**Methods to Increase Efficiency of Waterflooding in Naturally Fractured Reservoirs**

**Horizontal Well.** Recent research on horizontal wells has focused increasingly on fractured reservoirs. One of the research objectives is to increase horizontal well productivity compared to that obtained with vertical wells.
Due to its length, often much greater than that of a vertical well, a horizontal well can intercept many more fissures than a vertical well, thus obtaining higher productivity.

Since the average reservoir pressure in the Spraberry Trend Area is different from area to area, the average reservoir pressure was varied from 1000 psia to 1500 psia with different lengths of horizontal well sections. The simulations were performed using a constant plateau rate of 100 BOPD, no water injection, and 500 psi bottomhole pressure for 10 years. These simulations were by no means optimized, but performed to illustrate the potential benefits associated with horizontal wells in the Spraberry oil province. The simulation result is shown in Fig. 16.

The horizontal production well represents a significant improvement over the vertical production wells. The use of a horizontal production well could result in three to five times more cumulative oil production than that obtained using a vertical production well. Thus, horizontal production wells could reduce the number of wells by a factor of two. In addition, the cost of a horizontal production well typically is only 1.2 to 1.5 times that of a vertical production well (per foot drilled). The simulation results clearly indicate the benefit of using horizontal production wells in the Spraberry Trend Area.

The simulation result also suggested that maintaining or increasing the average reservoir pressure is critical. Increasing the average reservoir pressure by 250 psia would almost double the oil production rate. The pressure can be maintained or increased by injecting water perpendicular to the fracture direction (staggered line drive pattern). This pattern will also delay the water breakthrough in the producing wells.

**Well Injectivity Optimization.** Elkin\(^{27}\) found that over-injection might have been responsible for low recovery in the Spraberry area. He showed that the water breakthrough was characteristic of the Spraberry at the stage of depletion and at high water injection rates. Schechter *et al.*\(^{2}\) also mentioned that after waterflooding was initiated in the Humble Pilot test, water breakthrough occurred in most producing wells.

Several simulation cases were performed to test these hypotheses. As a base case, a vertical well with natural depletion was run followed by a case using injection wells. The water injection rate from each well varied from 100 to 1000 stbw/d. These simulations were run for 10 years with 500 psia BHP and 600 psia average reservoir pressure.

The size of the reservoir model was reduced to 40-acre at a 500 ft length perpendicular to the fracture direction. The grid dimension was 15 x 15 x 3 and the pattern was set up to be a staggered line drive pattern.

Figure 17 shows the effect of the vertical production well with and without the vertical injection wells on the oil production rate. The initial oil rate of 12 bbls/d was produced with natural depletion and only 8 bbls/d average oil rate afterward. The water was injected 1000 stbw/d per well from four vertical injection wells. At about 1.5 years after initiation, the water started to sweep oil to the production well until the production rate peaked at 50 bopd. As water was produced, the oil rate decreased sharply to zero oil production rate by about eight years. The cumulative oil production for the injected case was double that of the case without injection.

The effect on the oil production rate of the horizontal production well with and without the vertical injection wells is displayed in Fig. 18. The horizontal well section was set at a 500 ft length perpendicular to the fracture direction. Two cases were run, natural depletion (without injection wells) and waterflooding (with injection wells). In the natural depletion case, the use of a horizontal production well increased cumulative oil production four times over that predicted by the vertical production well. At the initial time, 75 bopd was produced, 6.25 times more than that produced by the vertical well. As in the case of a vertical production well, the production rate from the horizontal production well decreased as pressure decreased. However, the oil production rate declined much faster because of a higher pressure drop than in the vertical well case.

In the waterflooding case, four vertical injection wells were used. The water started sweeping oil after six months, producing faster than a vertical production well. This is because the horizontal production well had a larger drainage area. Production peaked at 100 bopd for about one year.

The oil peak rate was also longer than from a vertical production well because the horizontal production well sweeps the oil bank from the fracture more uniformly, causing a delay in water breakthrough. Using a horizontal production well with vertical injection wells could recover oil almost 30% over recovery obtained without injection wells.

In addition to setting the horizontal section perpendicular to the fracture direction, a case using a parallel to the fracture direction was also performed. However, the oil production rate was lower, recovering 25% less oil than in the case of the horizontal well with natural depletion (Fig. 18). The poor performance was because the horizontal production well did not intersect with the matrix rock, and therefore, the pressure drop could not be maintained. The effect of water injection on oil rate was observed at the same time as it was for the vertical production well, because of the similar distance to the vertical injection wells.

The simulation results from vertical and horizontal production wells with vertical injection wells show that it is crucial to optimize the water injection rate in order to delay water breakthrough in naturally fractured reservoirs. Two optimizations can be applied; either by reducing the injection rate or by using a cyclic waterflood. This study will be discussed later.

For the next scenarios, the performances of vertical and horizontal production wells were compared by using horizontal injection wells. Only two horizontal injection wells were opened. The horizontal injection wells were parallel to the fracture direction because the injection wells should push the oil from the matrix to the fractures (forced...
imbibition) and to the production well. Figure 19 shows that although the oil peak rates were lower in both vertical and horizontal production wells, the high production rates were maintained longer and the cumulative oil productions were higher than those obtained by using vertical injection wells. The response of water injection was delayed because both vertical and horizontal injection wells used the same water injection rate (1000 stbwd).

Several simulations were conducted to optimize the water injection rate for both vertical and horizontal injection wells. The water injection rate for each injection well was varied from 100 stbwd to 1000 stbwd. The simulations were run until zero oil production occurred and the cumulative production rate from each injection rate was recorded, as shown in Figs. 20 and 21.

For the constant injection rate case, the simulation results show that the optimum injection rate for each vertical injection well to produce the maximum cumulative oil production (235.751 MSTB) from the horizontal production well is 200 stbwd. Using 400 stbwd injection rate for each horizontal injection well, the horizontal production well produced 221.048 MSTB cumulative oil production. Thus, the horizontal production well with the vertical injection well could produce 15 MSTB higher than that with horizontal injection wells. However, the injection rate from the vertical injection well was more sensitive than that from the horizontal injection well. For instance, when the high injection rate (above 500 stbwd) was used, the cumulative oil production from the horizontal production well with horizontal injection wells was significantly higher than that with vertical injection wells.

This study has shown that using vertical injection wells with high injection rates (greater than 500 stbwd per well) is not successful in the 40-acre fractured Spraberry reservoir. Study results show that the optimum injection rate for a horizontal production well is about twice that of a vertical injection well.

Cyclic Waterflooding. The difference between natural depletion and waterflooding performance, as previously discussed, led to the use of a cyclic operation. Since reservoir pressure declines rapidly due to production, water injection is required to restore the pressure and is followed by producing a well without any water injection.

This cyclic operation was performed to observe the effect on the oil production rate. Two cyclic schemes were conducted; the cyclic rate scheme of 2:2 and the cyclic rate scheme of 1:2. The cyclic rate scheme of 2:2 means two years producing without waterflood, followed by producing with a waterflood for the next two years. The results of the cyclic rate schemes were compared to constant injection rate results as shown on Figs. 20 and 21. The simulation results show that the cyclic rate scheme of 1:2 gave the highest cumulative production rate, followed by the cyclic rate scheme of 2:2 and the constant injection rate. This is because cessation of water injection permits capillary force to hold much of the water in the rock. During pressure reduction, capillary force aids in the expulsion of oil from the matrix into the fractures (a similar concept was also proposed by Elkins).  

Conclusions
The major conclusions can be drawn as follows:

1. It has been shown that conventional dual porosity with variable permeability cannot be used to model high production rates.
2. The stress-transfer effect in naturally fractured reservoirs was shown to be important.
3. Low imbibition capillary pressure was generated from the model in order to match the experimental data. Laboratory experiments indicate that the wettability of the core plug was weakly water-wet.
4. The rate of imbibition was not sensitive to water relative permeability and water viscosity.
5. This study has shown that spontaneous imbibition cannot be used to illustrate the actual process of waterflooding in naturally fractured reservoirs.
6. Capillary pressure (Pc) obtained from dynamic imbibition modeling was used as verification of Pc used in the Humble Pilot simulation.
7. Use of horizontal production wells could increase cumulative oil production by three to five times, compared to vertical production wells in the Spraberry formation.
8. Increasing the average reservoir pressure would significantly increase the oil production rate.
9. A horizontal production well surrounded by vertical injection wells could give higher cumulative oil production than that obtained with horizontal injection wells, if the injection rate can be optimized. However, the production rate with vertical injection wells is more sensitive than that of horizontal injection wells.
10. High water injection (greater than 500 STBW/D per well) using vertical injection wells with a constant injection scheme is not successful in a 40-acre fractured Spraberry reservoir.
11. Optimization of the injection rate is important prior to conducting waterflooding in naturally fractured reservoirs.

Nomenclature

- \( b \) = porosity-compressibility coefficients, LT\(^2\)M\(^{-1}\)
- \( c \) = compressibility, LT\(^2\)M\(^{-1}\)
- \( D \) = diffusion coefficients, ML\(^3\)T\(^{-2}\)
- \( e \) = volumetric strain, dimensionless
- \( E \) = Young’s modulus, ML\(^{-1}\)T\(^{-2}\)
- \( f \) = fractional flow, dimensionless
- \( G \) = shear modulus, ML\(^{-1}\)T\(^{-2}\)
- \( k \) = permeability, L\(^2\)
- \( kr \) = relative permeability, dimensionless
- \( p \) = fluid pressure (+ for compression), ML\(^{-1}\)T\(^{-2}\)
- \( Pc \) = capillary pressure, ML\(^{-1}\)T\(^{-2}\)
- \( S \) = saturation, fraction
- \( t \) = time, T
- \( u \) = displacement, L
\( \nu = \) poisson ratio, dimensionless

**Subscripts**

- \( b \) = bulk
- \( c \) = confining
- \( \text{eff} \) = effective
- \( f \) = fluid
- \( i,j \) = integer denoting cell location in the x- and y-directions.
- \( n \) = index of primary and secondary pores
- \( o \) = oil
- \( p \) = pore
- \( s \) = solid
- \( t \) = total
- \( w \) = water
- \( l \) = primary pores
- \( 1 \) = secondary pores

**Superscripts**

- \( * \) = single porosity nonfractured system

**Greek**

- \( \alpha \) = effective stress coefficient associated with the bulk volumetric change, dimensionless
- \( \beta \) = effective stress coefficient associated with the pore volumetric change, dimensionless
- \( \deltaij \) = Kronecker’s delta \( \deltaij = 1 \) for \( i=j \), \( \deltaij = 0 \) for \( i \neq j \)
- \( \varepsilon \) = strain, dimensionless
- \( \phi \) = porosity, fraction
- \( \Gamma \) = interporosity flow, \( \text{L}^2/\text{T}/\text{L}^3 \)
- \( \mu \) = fluid viscosity, \( \text{ML}^{-1}\text{T}^{-1} \)
- \( \nu \) = Poisson’s ratio, dimensionless
- \( \rho \) = fluid density, \( \text{ML}^{-3} \)
- \( \sigma \) = shape factor, \( \text{L}^2 \)
- \( \nabla \) = gradient
- \( \nabla_t \) = divergence

**Acknowledgements**

This work was financially supported by the United States Department of Energy’s National Petroleum Technology Office under Contract No. DE-FC22-95BC14942. Support from the following companies is gratefully acknowledged: Chevron, Martahon Oil Co., Mobil Research and Development Corp., Mobil E&P USA, Pioneer Natural Resources (formerly Parker and Parsley Petroleum Co.), Petroglyph Operating Co., Texaco E&P Technology Dept., The Wiser Oil Co. and Union Pacific Resources. GeoQuest donated software to New Mexico Petroleum Recovery Research Center and used in reservoir simulation is also gratefully acknowledged.

**References**


Table 1—RESERVOIR PROPERTIES FOR THE HUMBLE PILOT FLOOD

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Original Reservoir Pressure, psia</td>
<td>2300</td>
</tr>
<tr>
<td>Saturation Pressure, Psia</td>
<td>1840</td>
</tr>
<tr>
<td>Reservoir Temperature, °F</td>
<td>140</td>
</tr>
<tr>
<td>Initial Water Saturation, %</td>
<td>30-35</td>
</tr>
<tr>
<td>Initial Oil Saturation, %</td>
<td>65-70</td>
</tr>
<tr>
<td>Matrix Porosity, %</td>
<td>6 - 18</td>
</tr>
</tbody>
</table>

Effective Permeability, mD 2.0-183.0
Matrix Permeability; mD; Area 0.1 - 0.5 Vertical 0.05-0.25 Pore Compressibility, psi¹ 4.00E-6

Table 2—RESERVOIR FLUID PROPERTIES

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Formation Volume Factor, gm/cc</td>
<td>1.385</td>
</tr>
<tr>
<td>Density of Residual Oil, gr/cc</td>
<td>0.851</td>
</tr>
<tr>
<td>Molecular Weight of Residual oil</td>
<td>217</td>
</tr>
<tr>
<td>Stock Tank Oil Gravity, °API</td>
<td>37.8</td>
</tr>
<tr>
<td>Gas Specific Gravity</td>
<td>0.932</td>
</tr>
<tr>
<td>Density of Stock Tank Water, gr/cc</td>
<td>1.010</td>
</tr>
<tr>
<td>Water Formation Volume Factor, bbl/STB</td>
<td>1.003</td>
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<tr>
<td>Water Viscosity, cp</td>
<td>1.2486</td>
</tr>
<tr>
<td>Water Compressibility, psi¹</td>
<td>3.00E-6</td>
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</tbody>
</table>

Table 3—MATCHED PARAMETERS FOR MATRIX

<table>
<thead>
<tr>
<th>Property</th>
<th>Symbol</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>φₘ</td>
<td>10.0 %</td>
</tr>
<tr>
<td>Permeability in the x-direction</td>
<td>Kₓ</td>
<td>0.02 md</td>
</tr>
<tr>
<td>Permeability in the y-direction</td>
<td>Kᵧ</td>
<td>0.02 md</td>
</tr>
<tr>
<td>Permeability in the z-direction</td>
<td>Kᵦ</td>
<td>0.02 md</td>
</tr>
</tbody>
</table>

Table 4—MATCHED PARAMETERS FOR FRACTURES

<table>
<thead>
<tr>
<th>Property</th>
<th>Symbol</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>φ</td>
<td>0.1 %</td>
</tr>
<tr>
<td>Fracture Permeability Ratio</td>
<td>kₓf/kᵧf</td>
<td>15/0.25</td>
</tr>
<tr>
<td>Shape Factor</td>
<td>σ</td>
<td>1.47</td>
</tr>
<tr>
<td>Major Fracture Orientation</td>
<td></td>
<td>N50°E</td>
</tr>
</tbody>
</table>
Fig. 1—The unitized portion of the Spraberry Trend Area, showing the location of the Humble pilot area.

Fig. 2—Comparison of performance between conventional and stress dual-porosity simulators.

Fig. 3—Matching between spontaneous-imbibition experiments with numerical solution.
Fig. 4—Imbibition capillary pressure obtained from matching spontaneous imbibition data.

Fig. 5—Matching between experimental data and the numerical solution (Spraberry core - cumulative water production).

Fig. 6—Matching between experimental data and the numerical solution (Spraberry core - cumulative oil production).

Fig. 7—Comparison between capillary pressure obtained from numerical simulation and laboratory experiment (Spraberry core).

Fig. 8—The Spraberry fracture system schematic.
Fig 9—Humble pilot test showing that the center production well increased by over 250 bopd after waterflooding. The wells in the outside of the pattern influenced by injected water from the pilot wells can be seen to occur along the fracture trend.

Oil-gas Relative Permeability

Fig 10—Grid model is oriented to N50°E along the major fracture system.
Fig. 11—Matrix and fracture relative permeabilities.

Fig. 12—Match of observed data and simulated data for oil production rate.

Fig. 13—Match of observed data and simulated data for water production rate.

Fig. 14—Match of observed data and simulated data for gas production rate.

Fig. 15—Match of observed data and simulated data for bottom hole pressure.
without vertical injection wells on the oil production rate.

Fig. 16—Effect of average reservoir pressure on cumulative oil production.

Fig. 17—The effect of a vertical production well on the oil production rate.

Fig. 18—The effect of a horizontal production well with and without vertical injection wells on the oil production rate.

Fig. 19—The effect of vertical and horizontal production wells
with horizontal injection wells on the oil production rate.

Fig. 5.20 – The effect of a horizontal production well with vertical injection wells and different injection schemes on cumulative oil production.

Fig. 5.21 – The effect of a horizontal production well with horizontal injection wells and different injection schemes on cumulative oil production (note: the cumulative oil production is lower than that shown in the previous figure).