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FOREWORD

The Quarterly Technical Report, NIPER-700, is submitted in accordance with the provisions of Cooperative Agreement DE-FC22-83FE60149 between the Department of Energy and the IIT Research Institute. The report is submitted in two volumes, Volume I representing the work accomplished under Fuels Research and Volume II the work for Energy Production Research during the period April 1—June 30, 1993.

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CHEMICAL FLOODING— SUPPORTING RESEARCH

DEVELOPMENT OF IMPROVED CHEMICAL FLOODING METHODS

**Cooperative Agreement DE-FC22-83FE60149,
Project BE4A**

**National Institute for Petroleum
and Energy Research
Bartlesville, Oklahoma**

**Contract Date: October 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1992: \$640,000**

**Principal Investigators:
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**Project Manager:
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Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this year's work are (1) to apply advanced EOR technology, based on mixed surfactant systems, to improve oil recovery from Class 1 and other DOE targeted reservoirs; (2) to adapt surfactant EOR

technology to different salinity and temperature ranges by developing surfactant systems that are tolerant to changes in chemical composition in selected reservoirs; and (3) to develop cost-effective systems for selected applications using low concentration surfactants with alkaline additives or other sacrificial agents. Studies will concentrate on problem areas which have adverse effects on performance and economics of chemical EOR in order to achieve a balance between cost and oil recovery effectiveness.

Summary of Technical Progress

Mixed Surfactant Systems

A series of phase behavior studies was conducted on selected combinations of TRS 10-410/IBA system and nonionic surfactants of the Genapol and Igepal series. These studies included salinity scans with several alkanes, including n-octane, n-decane, and n-dodecane under different temperature conditions. Similar salinity scans were also conducted with the individual nonionic surfactant components at the different hydrophilic-lipophilic balance (HLB) values with the different alkanes. These experiments were conducted over a broad range of temperatures, from room temperature up to 80° C. These results will be compared to the results of the optimal salinity values obtained from earlier phase inversion temperature (PIT) studies and will help provide information on the degree of oil/water solubilization capacity of these types of chemical systems. These experiments have been completed, and the results are being analyzed.

The results of the PIT studies on the Igepal and Genapol nonionic surfactants were used to develop models of surfactant behavior. These early studies included some systems containing an anionic primary surfactant system of TRS 10-410/IBA. The work on developing these correlations is ongoing. For the systems containing the Igepal surfactants, a general analytical expression was possible of the form:

$$\ln S^* = a_0 + a_1 \cdot T + a_2 \cdot [\text{HLB}] + a_3 \cdot [\text{ACN}] \cdot T$$

This expression was based on the variation of the log of the optimal salinity (S^*) of the overall chemical system with temperature (T), alkane carbon number (ACN) of the oil, and the HLB of the surfactant. The chemical systems containing Genapol surfactants did not correlate well with this general expression. A more complex expression was needed to correlate the variation of optimal salinity with the different experimental parameters. Other forms of the expression are being evaluated. Efforts to correlate the behavior of the chemical systems in combination with the TRS 10-410/IBA system are also in progress. The effects of adding the anionic component on the $\ln S^*$, $d\ln S^*/dT$, $d\ln S^*/d[\text{ACN}]$, and $d\ln S^*/d[\text{HLB}]$ of the different chemical systems are also being examined.

Surfactant Loss—Mixed Surfactants

When mixtures propagate through porous media, there is a tendency to adsorb and to separate. These processes may lead to the loss of the effectiveness of expensive chemicals. It is therefore important to determine the ability of a mixture to propagate through a porous medium such as a petroleum reservoir.

The surfactants selected were currently available, commercial surfactants: Stepan B-100, an alkyl aryl sulfonate (anionic), and Igepal DM-530, a dinonylphenoxy ethoxylate (nonionic). A moderate salinity brine of 1% NaCl was selected. The anionic surfactant does not separate or precipitate in this brine. Solutions of each individual surfactant were prepared containing 1% active weight of surfactant in 1% NaCl. A mixture was also prepared containing 1% of each surfactant in 1% NaCl. No low-molecular-weight alcohol was added to any of the solutions.

A solid with a high surface area was chosen which has different adsorption capacities for anionic and nonionic surfactants so that a good chance of separation might occur. Silica gel with 330 m²/g was used for the static tests and to make an unconsolidated sandpack. Reservoir material generally has a specific surface of 1 to 2 m²/g, and the clay content is responsible for most of that area. An unconsolidated sandpack of silica gel 1 foot long can represent the silica content of a few hundred feet in the reservoir.

Ionic surfactant was analyzed using a well-known two-phase titration method.¹⁻² This method is a two-phase, dye-transfer titration using hexadecyltrimethyl ammonium bromide as titrant and methylene blue as indicator. The

sample, an aqueous solution of indicator, and chloroform were added to a volumetric flask and shaken. In the presence of sulfonate the bottom layer is highly colored. The titrant is added until both layers have the same color intensity. Sample sizes were scaled so that less than 2 mL of titrant was used. Stock solution of the mixed surfactants was used to standardize the titration. The nonionic surfactant does not interfere with this procedure.

The method of Boyer et al.³ was selected to determine the concentration of the nonionic surfactant. This method consists of the separation of the nonionic from the anionic surfactant and the colorimetric determination of the nonionic surfactant. A 1-mL sample is washed through an anion-exchange column of BioRad™ AG™ 1-X to retain the anionic surfactant while the nonionic surfactant is eluted with methanol. The methanol is removed on a rotovap, and the dried nonionic surfactant is taken up in methylene chloride. Aqueous cobalt thiocyanate solution is added and shaken, and the organic layer is separated. The optical absorbance of the organic layer is measured at 620 nm.

For static adsorption determination, various measured amounts of silica were added to various amounts of test solution in capped tubes. These tubes were agitated for at least 24 hours and then allowed to settle. Aliquots were removed and analyzed for surfactant concentration. The test solutions were anionic alone, nonionic alone, and the two surfactants mixed. These static tests resulted in the following values of adsorption, all in mg/m²: anionic alone, 0.79 ± 0.02; nonionic alone, 2.42 ± 0.4; anionic from mixed solution, 1.13 ± 0.3; nonionic from mixed, 1.78 ± 0.4. The CMCs of the anionic, nonionic, and mixed surfactants are much lower than 1%; therefore, these adsorption quantities are maximum or plateau adsorptions. Each surfactant affects the adsorption of the other. The nonionic increases the anionic adsorption, probably because the anionic surfactant interacts with the adsorbed nonionic surfactant by chain-chain interactions; while the anionic decreases the nonionic adsorption perhaps because it incorporates charges into the adsorption layer. A simple adsorption model based on these results was constructed. This model is shown as the light lines of Fig. 1.

An unconsolidated sandpack of silica gel was used for the dynamic flow test. The results of this flow test are shown as the heavy lines in Fig. 1. The dynamic flow test followed the model in a very general way, but not in detail.

There are some similarities as well as striking differences between the model and the dynamic tests. Both show the separation of surfactants occurring, with the anionic surfactant running ahead of the nonionic. They agree that during the separation phase, the difference between the concentrations of the surfactants (as shown by the vertical separation of the curves) is about the same, namely about 0.35 C/C₀ units. The 1:1 ratio of surfactants appears at about 280 mL.

Of more significance is that in the dynamic test, the surfactants broke through much sooner than the model predicts. At least some of both surfactants moved through the silica gel, although in approximately a 2 to 1 ratio of anionic to nonionic in the early stages of the dynamic test.

Fig. 1 Relative effluent concentration profile of anionic and nonionic surfactant in a mixed surfactant system compared to that from a simple dynamic adsorption model. Porous medium is a high surface area silica gel.

Thus the surfactants penetrated further through the porous medium than predicted by the model. Even though a large amount of fluid has passed through the sandpack, the total adsorption of each surfactant in the dynamic test is about 75% of the amount predicted by the static tests.

There are several reasons for these differences. The model is based on an over-simplified adsorption isotherm, which assumes that the surface will strip all surfactant from a stream of low-concentration fluid until its adsorption capacity is reached, and then stop adsorbing. However, in the dynamic situation, the surfactant concentration is lowered, but not reduced to zero. During flow through the unconsolidated particles, part of the fluid in contact with the particle moves very slowly, and adsorption occurs through this semi-stagnant layer. Thus fluid moves forward before complete adsorption equilibrium is established. Another process occurring is that the adsorption of one surfactant may influence the behavior of the other in ways that alter the dynamics of the process. In the dynamic test, the silica which is closer to the exit is bathed with fluid much depleted in nonionic surfactant so that some anionic surfactant adsorbs on the silica surface. This anionic surfactant interferes with the ability of the nonionic surfactant to adsorb when it comes later. Additional details are being reported.⁴

The ability to propagate surfactant systems through the reservoir is important for successful application of chemical EOR technology. In this investigation, the general features of a simple model for the propagation of mixed surfactant systems were found in the dynamic flow test. The surfactant mixture traveled through the sandpack in a different ratio than the injected ratio until the adsorption requirements were satisfied. Propagation of surfactants through porous media will continue to be an important part of future work on surfactant systems.

CT Imaging of Oil Recovery in Class 1 Reservoir Rock

North Burbank Unit Core

Analysis of rock permeability and porosity prior to use in coreflood experiments is important to help evaluate fluid movement and oil recovery. Prior to conducting a CT-imaging coreflood test, a core sample from North Burbank Unit (NBU) reservoir, Osage County, Oklahoma was cleaned, and a permeability distribution was obtained on the core faces using a minipermeameter, which measures permeability to N₂ gas for a small area of the core surface. After cleaning, dark colored stains appeared on a portion of the previously unmarked core surface. They may represent areas of different mineralization and are in the process of being examined by a geologist. The minipermeameter indicated that the stained areas were lower in permeability than the adjacent areas of the core. Figure 2 shows the permeability variation observed along the core faces.

A tracer test using CT to image the fluid distribution indicated that the lower permeability zone extended through the core in a plane that approximately connected the 10-mD areas on the core faces, dividing the core into two higher permeability layers. The tracer in the lower half of the core reached the outlet more rapidly than the tracer in the upper half of the core. Figure 3 shows a vertical tracer profile along the length of the core. One cross-sectional slice that shows the lower permeability zone separating the upper and lower areas is also represented. This core will be used for a chemical flood test using a mixed surfactant chemical system. Monitoring the test using CT-imaging will demonstrate if the chemicals are injected uniformly in the two higher permeability zones.

Corefloods Using Hepler (Kansas) Oil

A series of coreflood experiments were conducted to determine if reducing the amount of injected surfactant would result in changes in oil bank formation, oil propagation, and overall oil recovery efficiency. The CT scanner was used to monitor oil movement, and results were compared with tests conducted previously using larger volumes of injected surfactant. An alkaline mixed surfactant system was used with Hepler (Kansas) oil. Tests were conducted in Berea sandstone core with permeability to brine greater than 500 mD to minimize the

Fig. 2 Permeability profile along NBU core faces obtained using a minipermeameter. Dark areas along core surface appeared after cleaning with toluene and methanol.

Fig. 3 CT images of tracer injection through NBU core, showing a vertical slice along the core length and a slice across the core. A lower permeability zone bisects two higher permeability zones. Permeability contrast is shown in Fig. 2.

effect of rock permeability on oil recovery. Previous studies had shown that oil recovery was reduced as rock permeability declined for the oil and chemical system used in this series of tests.⁵

Table 1 summarizes the chemical parameters and oil saturation results. Final oil saturations after chemical floods did not correlate with surfactant slug size injection. Differences in the experimental conditions and the oil movement through the core (as seen in the CT images) provide some clues to explain these results.

For test 1, the mobility control polymer was initially injected at an unfavorable mobility ratio. Although the polymer concentration was subsequently increased, the chemicals continued to channel through the core and failed to remobilize the oil. As a result, the overall oil saturation in the core after chemical flooding was higher than that for either test 2 which used a smaller surfactant slug or test 3 which repeated the conditions of test 1.

Oil saturations after the chemical flood for tests 2 and 3 were reduced to the same level even though twice as much surfactant was injected for test 3 as for test 2. For test 3,

however, the oil saturation after waterflood was lower than that for test 2. The waterflood for test 3 was conducted for a longer period of time, and oil continued to be produced in small amounts as the waterflood period was extended. The oil saturation level (25%) was lower than that of any previous test using Hepler oil. During the chemical flood, CT images of oil movement indicated that the remaining oil moved very slowly through the core. Chemicals may have first moved through the well swept zones of the core and may have been relatively less effective than if they had moved uniformly through the core. Tertiary oil breakthrough was delayed by at least 1 PV of injected chemical compared to the previous tests. CT images showed that some increase in oil saturation ahead of surfactant injection occurred. Continuous injection of polymer eventually moved this oil through the core. Although the overall recovery of this test was good, the economics of the process was poor because of the large amount of polymer that was injected. From the results of these tests, it cannot be concluded that oil recovery is a function of the amount of surfactant injected. A larger volume of low concentration surfactant is probably more effective than a small volume. However, other important factors including core heterogeneities, effect of mobility control polymers, and possibly residual oil saturation play important roles in producing the oil in these tests.

These tests will be described in detail in future reports, and CT images during various stages of fluid injection will be reproduced to allow visualization of oil production.

Surfactant Database

The volume of information on oil recovery using surfactant systems is fairly significant. To identify key areas of research that will need attention, the development of a database system was begun in FY92. The ultimate goal of this work is to develop a system to identify surfactants, or combinations of surfactants, that can be applied to targeted reservoir conditions. The overall system derives information from the literature as well as ongoing research in this area. The capability to identify structure-

TABLE 1

Coreflood Information and Residual Oil Saturations After Waterflood and Chemical Flood for CT-Monitored Chemical Flooding Experiments

Test No.	Core brine permeability, mD	Surfactant PV injected	Polymer PV injected	S _{orw} , %PV	S _{orcf} , %PV
1	597	0.54	2.7	28.2	18
2	530	0.20	3.8	31.5	11
3	720	0.43	5.7	25.0	13
CT-CF 1 from ref. 5	560	0.79	1.3	36.0	6

Chemical formulation = 0.4% total weight of a 62.5/37.5 mixture of Stepan B110/B105 (an alkyl aryl sulfonate and an ethoxylated sulfate) in 1% NaCl, 0.95N Na₂CO₃, and 0.95N NaHCO₃, 560 ppm and 3,500 ppm biopolymer mobility control polymer.

performance correlations from the multitude of combinations of surfactant types and structures that can be used in these formulations will be extremely helpful. The identification of chemical systems that strike a balance between cost and effectiveness will be critical in determining targeted applications of surfactant technology.

The database system in its present form is a two-part system. The first part is primarily a compilation of available literature in the chemical EOR area, containing the referenced sources of the literature citations. This section is referred to as the "Master Reference" section. Currently there are 1,805 references in this section. The second part or "Detailed" section has two modules or sections; the Detailed Reference section, a subset of the Master Reference section, contains references to articles which have been selected for more extensive examination so that they may be linked to the Detailed Surfactant section which contains the detailed information that has been filtered from the literature. It is the objective of this Surfactant section to summarize and compile the data on different surfactants that has been reported and to develop a system for identifying surfactant structure-performance correlations. These two modules together are referred to as the "Detailed" section. Currently there are about 150 entries in this section; of these about 100 have had detailed information physically entered into the database, including a complete summary which NIPER researchers have composed for each article.

As research on development of this technology continues, the Reference section of the database will be updated. The greatest amount of the work required to maintain the entire database package will need to be focused on the summary and on the Detailed Cross Reference section of the database, especially in developing correlations.

A more complete discussion of the database is presented in the Status Report "Development of a Chemical Flooding EOR Literature Database System" by Dr. Leo A. Noll which is now in the review process.

The database will need to evolve into some level of an "expert" system to provide researchers or design engineers some guidelines for decision making pertaining to implementation of chemical flooding EOR projects. Such a system would give researchers the capability to identify structure-performance correlations of different surfactants and their combinations for specific applications. The system needs to be robust and flexible as well as operable in different computer platforms. These capabilities will be needed because this type of a tool will also serve as a vehicle for technology transfer to interested parties in the petroleum industry.

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DEVELOPMENT OF IMPROVED ALKALINE FLOODING METHODS

Cooperative Agreement DE-FC22-83FE60149,
Project BE4B

National Institute for Petroleum
and Energy Research
Bartlesville, Oklahoma

Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$200,000

Principal Investigator:
Troy R. French

Project Manager:
Thomas B. Reid
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objectives

To develop cost-effective and efficient chemical flooding formulations using surfactant-enhanced, weakly alkaline systems. Specific objectives for FY93 are to (1) determine the effect of variables on surfactant and polymer propagation and retention during alkaline flooding and (2) perform studies designed to support a field test.

Summary of Technical Progress

Computed tomography experiments are in progress to determine accurately oil saturations in field cores that have been partially swept with surfactant-enhanced alkaline chemical formulations. It has recently been determined that this research is necessary because, due to heterogeneities in Midcontinent field cores, it is difficult to predict accurately the final oil saturations that result after application of chemical flooding methods in Midcontinent fluvial-dominated (DOE Class 1) reservoirs. The extent and significance of heterogeneity in these reservoirs has been shown recently to be greater than previously believed.¹⁻²

Reservoir heterogeneity does not adversely affect routine laboratory waterflooding results nearly so much as it affects chemical flooding. Large volumes of water are

injected during routine laboratory floodpots, and a pressure gradient is maintained across the core for long periods of time. Because of the much smaller slug sizes that are injected during chemical flooding, problems associated with channeling of injected fluids are much more pronounced.

Figures 1 and 2 show results from flooding field core from the Tucker sand of Hepler field with a chemical formulation that contains 0.1% active Chaser CF-100 surfactant, 0.45% active sodium tripolyphosphate (STPP), and 3.2% NaHCO_3 . Injection of 0.2 PV of the surfactant/alkali was followed with 0.2 PV of 1,200 ppm Alcoflood 1135 polyacrylamide polymer for mobility control. After injection of the chemical slugs, effluent water cut decreased sharply.

Sweep efficiency in this field core plug (well J-4, 584.4 ft depth) was much better than that in some previous floods conducted with Hepler field cores. The core plug was first waterflooded with tagged brine (NaI) to residual oil saturation, then chemical flooded with solutions that did not contain a tagging agent. Figure 2 shows the displacement of tagged (NaI) brine during injection of the chemical slugs. The chemical slugs appear to have swept approximately 55 to 65% of the total pore volume. Average core oil saturation after chemical flood was 24% PV. Core oil saturation after the flood was about 16% PV (by CT) in the area that was swept by the chemical flood.

The experiments confirm that the chemical formulation mobilizes oil in the swept volume of field cores, with residual oil saturations in the swept zones that approach prior results in Berea sandstone cores. Overall, however, oil recovery is less with field cores due to the smaller

Fig. 1 Water-oil ratio, coreflood RP 27E.

volumetric sweep obtained with field cores from the Tucker sand.

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Fig. 2 CT images during chemical flood, coreflood RP 27E.

MOBILITY CONTROL AND SWEEP IMPROVEMENT IN CHEMICAL FLOODING

**Cooperative Agreement DEFC22-83FE60149,
Project BE4C**

**National Institute for Petroleum
and Energy Research
Bartlesville, Oklahoma**

**Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$240,000**

**Principal Investigator:
Hong Gao**

**Project Manager:
Jerry F. Casteel
Bartlesville Project Office**

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this project are to develop improved methods for maintaining effective mobility control throughout the reservoir in chemical flooding, and to use the permeability modification simulator to design a cost-effective gel treatment using polymer gel systems. Specific objectives in FY 93 are (1) to determine the effect of lamination angle on polymer retention in unfired Berea cores, (2) to compare simulation results using NIPER's permeability modification simulator with field performance, and (3) to adapt NIPER's permeability modification simulator to run on IBM-PC/80386 or compatible microcomputers.

Summary of Technical Progress

Polymer Retention in Unfired Rectangular Berea Sandstone Cores

Corefloods designed to investigate the effect of lamination angle on polymer retention in cores were conducted with two unfired rectangular Berea sandstone cores, unf-30 (3.81 cm x 3.81 cm x 23.88 cm) and unf-90 (4.10 cm x 3.81 cm x 24.30 cm). Unf-30 was cut at 30 degrees with respect to the direction of laminations. Its porosity was 19% and brine permeability was 160 mD. Unf-90 was cut at 90 degrees with respect to the direction of laminations. Its porosity was 18.9% and brine permeability was 84 mD. For the unf-30, two slugs (3.5 and 4.5 PV or 232 and 298 mL) of a 1,000-ppm biopolymer solution in 2% KCl were injected into the core with each slug followed by about 10 PV of 2% KCl. The injection rate was 3.8 mL/hr or 1.09 ft/d (apparent shear rate = 10 sec^{-1}). For the unf-90, a first slug (3.53 PV or 253 mL) of a 1,000-ppm biopolymer solution in 2% KCl

was injected into the core followed by about 10 PV of 2% KCl. The injection rate was 3.0 mL/hr or 0.8 ft/d (apparent shear rate = 10.2 sec^{-1}). Effluent biopolymer concentration was determined by viscosity measurements at a shear rate of 20.4 sec^{-1} using a Contraves Low Shear 3C viscometer and comparing with a calibration curve.

Results showed that equilibrium retention was not reached in any of the corefloods conducted. Figure 1 shows the normalized effluent biopolymer concentration versus pore volumes (PV) injected for the corefloods with unf-30 core. To obtain equilibrium retention, more slugs of polymer injection are required. Figure 2 compares the cumulative polymer retention during and after the first slug of polymer injection into the unf-30 and unf-90 cores. The results show that polymer retention during polymer injection and post brine flood was higher in the unf-90 than in the unf-30. These results are similar to those obtained with fired Berea sandstone cores.¹ Compared with the unf-0 core² that was cut along the direction of laminations, polymer retention was higher in the unf-90 core and lower in the unf-30 core, as is shown in Fig. 2.

CT Tracer Tests

To determine how the retained polymer affected the stability of the fluid front in core, tracer tests were conducted before and after the polymer flow. Tracer tests with unf-30 were conducted at 1.54 ft/d or 5.4 mL/hr (apparent shear rate = 14.2 sec^{-1}) by injecting a slug (0.3 PV) of tagged brine (7% KI) into the core followed by 2% KCl brine. The flow behavior of the tagged brine was monitored throughout its advance through the core by conventional CT and topogram scanning. The resulting images before and after the polymer flow showed that the fluid front was more stable after the polymer flow. These results are similar to those observed with a similar but fired Berea core.

Fig. 1 Normalized effluent concentration profile for a biopolymer from an unfired Berea sandstone core.

Fig. 2 Retention of a biopolymer in unfired Berea sandstone cores during and after polymer flow.

PC-Based Permeability Modification Simulator

NIPER's permeability modification simulator on the MicroVax computer was downloaded to a PC-80486 computer and converted to a PC-based simulator. Simulation runs with the PC-based simulator on PC-80486/50 MHz and PC-80386/20 MHz computers showed that results were exactly the same. Running time with the PC-80486/50 MHz computer was 7.17 times faster than that with the PC-80386/20 MHz computer. Simulation runs with the PC-based simulator and with the simulator on the MicroVax computer showed that the differences in oil recovery rate, water production rate, water oil ratio, and fractional oil recovery were negligible as shown in Figs. 3 and 4.

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Fig. 3 Comparison of simulation results of oil and water production rates from a PC and a MicroVax computer.

Fig. 4 Comparison of simulation results of fractional oil recovery and water-oil ratio from a PC and a MicroVax computer.

SURFACTANT-ENHANCED ALKALINE FLOODING FIELD PROJECT

Cooperative Agreement DE-FC22-83FE60149,
Project SGP41

National Institute for Petroleum
and Energy Research
Bartlesville, Oklahoma

Contract Date: July 18, 1990
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$318,000

Principal Investigator:
Troy R. French

Project Manager:
Thomas B. Reid
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this pilot project are (1) to obtain information and data that will help to demonstrate the applicability of surfactant-enhanced alkaline flooding as a cost-effective EOR method, (2) to transfer the surfactant-enhanced alkaline flooding technology that has been developed under the sponsorship of the DOE to the petroleum industry, and (3) to obtain information regarding procedures for designing and applying this technology that will assist independent producers in sustaining production from mature producing oil fields rather than abandoning marginal wells.

Summary of Technical Progress

The site selected for conducting a field pilot test using surfactant-enhanced alkaline flooding methods is Hepler (Kansas) oil field. Hepler field is in Crawford and Bourbon counties. This near-term application of a promising EOR technology in a fluvial-dominated deltaic type reservoir is consistent with U. S. Department of Energy oil research strategy.

The Tucker sandstone from Hepler field was characterized using routine and advanced analytical methods, and these methods were compared. Traditional wireline logs indicate that the reservoir is vertically stratified on the foot scale. Routine core analysis, X-ray computed tomography (CT) scans, minipermeameter measurement, and petrographic analysis indicate that heterogeneity and lamination extend to the microscale. There was good agreement among the several methods used for characterization.

Geology of the Hepler site is typical of that of many Class 1 reservoirs.¹⁻² The Tucker sandstone (a local equivalent Bartlesville sand) of Hepler field is a Class 1 reservoir that was deposited in a fluvial dominated deltaic environment. Net sand thickness varies from 10 to 29 ft in the field, but is less than 16 ft in the pilot area. Average permeability is about 80 mD. The percentage of sand with greater than 100 mD permeability is 10 to 14% in the pilot area. Previous studies have concluded that depositional compartmentalization is a characteristic of many Midcontinent reservoirs.³⁻⁵ Well locations are shown in Fig. 1. Reservoir core was obtained from wells J-4, H-4, and G-5. Wells were air-drilled to a depth slightly above the Tucker sand, and after mudding-up, the entire sand interval was cored.

Fig. 1 Elmer C lease, Hepler (Kansas) oil field.

Fig. 2 Well H-4 spontaneous potential, gamma ray, and CT scan.

Reservoir Characterization by Conventional Analytical Methods

Wireline logs for well H-4 are shown in Fig. 2. The pay zone extends from approximately 576 to 587 ft depth. Spontaneous potential (SP) and gamma ray (GR) logs indicate a general fining-up of sand over the entire interval. The GR log, in particular, indicates the existence of multiple stacked point bar sands, with a fining-up nature for each sand body. The scale of resolution of the wireline logs is in feet. Logs from wells J-4 and G-5 are very similar to well H-4 logs, with a slight thinning of pay from south to north.

Reservoir Characterization by Advanced Analytical Methods

The entire sand interval in each well was analyzed by X-ray computed tomography (CT) using third-generation equipment originally designed for medical applications and modified for rock analysis with special software and a high-accuracy positioning table. The mathematical relationships for correlation of CT density and rock-fluid properties have been described.⁶ Instrument resolution is 0.5 mm. CT-derived core permeability of the interval from 579.5 to 585.5 ft depth in well H-4 is shown in Fig. 3. Areas of high permeability are shown in dark shades; low permeability in light shades. Sands with the highest permeability are shown as nearly black, whereas areas with low permeability are shown in white. From Fig. 3, the lenticular, laminated nature of the sand is apparent. Laminations extend from the top of the sand to the bottom of the sand. Laminations extend across the entire width of the core (3 in.). Most of the laminations appear to be nonparallel, and from the apparent angles of individual laminations, it is concluded that the horizontal width of individual sand compartments is less than previous estimates.⁴ The horizontal width of individual compartments is probably on the feet or tens of feet scale. Some high-energy foreset beds are visible in the lower

Fig. 3 CT derived permeability, Well H-4.

parts of the sand, and these trough-bedded zones contain the most vertically homogeneous sand bodies.

Figure 2 also directly compares CT as an analytical technique with the wireline logs. The CT image shows the sand interval between 584.5 and 585.5 ft to be much more complex than that indicated by wireline logging. CT shows that this 1-ft interval is the result of many cut-and-fill cycles. The interval between 585.0 and 585.5 ft is some of the most uniform sand in the core from well H-4, but CT imaging reveals the existence of high-permeability variation, on the fraction of an inch (millimeter) scale, over this 0.5-ft interval.

Summary and Conclusions

Cores from the Tucker Sandstone from Hepler oil field were examined with routine and advanced analytical techniques. Routine core analyses and wireline logs indicated that sand properties vary with depth. Wireline logs indicate a general fining-up sequence, with several point bar sands being identifiable. Routine analyses of core plugs, taken at 1-ft intervals, demonstrated that 100% and greater changes in permeability occur over small vertical reservoir distances.

Cores were also evaluated with advanced analytical techniques: X-ray computed tomography (CT), petrographic image analysis (PIA), and a minipermeameter. Advanced analytical techniques demonstrated that compartmentalization and lamination extend to the microscale. There was good agreement among all analytical methods, with advanced techniques allowing better resolution at smaller scales than could be achieved with the routine methods used for reservoir characterization.

Analytical information from three wells is hardly sufficient to characterize an entire reservoir. However, sufficient information is available to obtain a very good idea of the heterogeneities that exist vertically. The three cores had remarkably complex, yet similar structures.

Fig. 4 Hypothetical Tucker Sandstone Model.

It was not possible to identify individual layers that extend from well to well. The complexity of the layering and the angles of individual layers, which are not exactly parallel, indicate that individual sand bodies probably extend horizontally for only a few feet or tens of feet. Figure 4 shows an idealized model of how the reservoir is probably structured: complex layering with small compartments.

Flow patterns during tracer tests in cores were adequately explained by characterization of core plugs with advanced analytical techniques. Channeling of injected fluids occurred in laboratory experiments because, on core plug scale, permeability streaks extended the full length of the core plug. However, flow patterns during reservoir flooding should be considerably different than the flow patterns observed with small core plugs. Previous laboratory experiments, conducted with outcrop samples of Tallant sandstone, have shown much better sweep by injected fluids in situations where the fluids must traverse through many small compartments of variable permeability similar to those in the Tucker sandstone,⁷ and several field-scale waterfloods conducted in the Tucker sandstone were reported as successful.⁸

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GAS DISPLACEMENT— SUPPORTING RESEARCH

GAS FLOOD PERFORMANCE PREDICTION IMPROVEMENT

**Cooperative Agreement DE-FC22-83FE60149,
Project BE5A**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$250,000**

**Principal Investigator:
Ting-Horng Chung**

**Project Manager:
Jerry F. Casteel
Bartlesville Project Office**

Reporting Period: April 1 - June 30, 1993

Objective

The objective of this research project is to improve prediction techniques for gas miscible displacement through fundamental research in displacement mechanisms. The

effects of carbon dioxide on interfacial tension and relative permeability for reservoir fluids is the research subject of this project.

Summary of Technical Progress

IFT Measurement for Hydrocarbon-Water Systems

A high-pressure interfacial tension (IFT)-measurement apparatus has been constructed for IFT measurements of CO₂, water/brine, and hydrocarbon/oil systems. The hardware and the method for IFT measurement of pendant drops using video image profile matching have been described.¹ Calibration has been completed. Measurements were conducted for water surface tension and the IFT of water and n-pentane at various temperatures. Results are shown in Figs. 1 and 2. Figures 1 and 2 show that our measured surface tension and IFT values agree well with literature reported data.²⁻⁵ For the IFT of n-pentane-water, our measured values and the two sets of literature data are slightly scattered. The accuracy of IFT measurements depends on the purity of both fluids. In our measurements, water is purified by distilling deionized water with potassium permanganate and then stored in a sealed bottle. The purity of n-pentane is 99.9+%. All fluids are handled carefully during experiments to protect from air dust. IFT measurements for CO₂, water, and hydrocarbon systems at elevated pressures are in progress.

Fig. 1 Comparison of measured water surface tension.

Fig. 2 Comparison of measured n-pentane-water IFT.

Prediction of CO₂-Solubilities in Hydrocarbon and Water/Brine Phases

To measure the IFT for CO₂-saturated water/brine and hydrocarbon/oil systems, an accurate prediction technique for CO₂ solubility in aqueous and nonaqueous phases is required. Conventional equations of state (EOS) such as the Peng-Robinson (PR) EOS and the Soave-Redlich-Kwong (SRK) EOS cannot adequately predict the phase behavior of CO₂-aqueous systems. Several modifications to cubic EOSs have been proposed to achieve a better prediction for the phase behavior of mixtures including water.⁶⁻⁸ The previous quarterly report,¹ presents the result of a modified PR-EOS proposed by Soreide and Whitson (1992)⁶ for CO₂ with pure water and NaCl brine. This new modified PR-EOS suffers some shortcomings: (1) it is inaccurate in vapor pressure predictions for pure water and CO₂, (2) it is thermodynamically inconsistent using two different values of the attractive term "a", and (3) it is not good for extrapolation. Recently, Twu et al. (1991)⁹ presented a new α -function for the attractive term

"a" of cubic EOS. The new modified Redlich-Kwong (RK) EOS is given as

$$P = \frac{RT}{(v-b)} - \frac{a(T)}{v(v+b)} \quad (1)$$

where

$$a(T) = a(T_c)\alpha(T) \quad (2)$$

$$a(T_c) = 0.427481R^2T_c^2/P_c \quad (3)$$

$$b = 0.086641 RT_c/P_c \quad (4)$$

and the new α -function

$$\alpha(T) = T_r^{2(m-1)} e^{l(1-T_r^m)} \quad (5)$$

where $T_r = T/T_c$; l and m are parameters for each compound. With the new α -function, the modified RK EOS can model vapor pressures of water and CO₂ from the triple point to the critical point within 1% accuracy. The results are shown in Fig. 3. So, this modified RK EOS is accurate for both pure water and CO₂. For binary mixtures, Twu et al.⁹ proposed a new mixing rule as

$$a_m = \sum \sum x_i x_j a_{ij} \quad (6)$$

$$b_m = \sum x_i b_i \quad (7)$$

$$a_{ij} = (a_i a_j)^{1/2} [(1 - k_{ij}) + (k_{ji} - k_{ij}) x_j^2] \quad (8)$$

For a binary system, there are two binary interaction parameters, k_{12} and k_{21} . They are temperature-dependent. This modified RK-EOS was tested with experimental data for CO₂ solubility in pure water. Results are shown in Fig. 4. It can be seen that this modified RK-EOS is able

Fig. 3 Vapor pressures of CO₂ and water.

Fig. 4 CO₂ solubility in water.

to predict CO₂ solubility in water at extremely high pressure conditions with reasonable accuracy. The results were calculated with $k_{\text{water-CO}_2} = 0$ and $k_{\text{CO}_2\text{-water}} = 0.277365 - 123.38/T(\text{K})$. More accurate results can be obtained by optimizing the two binary interaction parameters. However, this modified RK-EOS is still not accurate in density prediction (the same shortcoming as that of other cubic type EOS) and needs to be improved.

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MOBILITY CONTROL, PROFILE MODIFICATION, AND SWEEP IMPROVEMENT IN GAS FLOODING

Cooperative Agreement DE-FC22-83FE60149,
Project BE5B

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$375,000

Principal Investigators:
Clarence Raible

Project Manager:
Jerry F. Casteel
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this project are (1) to conduct phase behavior experiments and evaluate feasibility for alcohol-induced salt precipitation as a method for profile modification, (2) to conduct experiments to change permeability of porous media using salt precipitation, and (3) to conduct profile modification studies using polymer gels or alcohol-induced salt precipitation as methods to modify flow profiles.

Summary of Technical Progress

Waterflooding Experiments with Parallel Cores

Waterflooding experiments were conducted with high- and low-permeability cores in parallel to demonstrate profile modification using alcohol-induced salt precipitation. Berea sandstone cores were used for these experiments, except coreflood 1 where a 200 to 325 mesh sandpack was used to obtain a larger permeability contrast. Permeability contrasts between high- and low-permeability cores ranged from 3 to 10. The cores were about 28 cm in length with a diameter of 3.8 cm. Table 1 shows a further description of core dimensions and properties.

All experiments were conducted at room temperature (22° C), and the cores were initially saturated with NaCl-saturated brine. With the core and coreholder mounted vertically, oil was injected into the top inlet until the oil-water ratio was 50 or greater. Crude oil from Hepler (Kansas) oil field was used for the parallel coreflood experiments. Oil from Hepler field had a viscosity of 67 cP at 22° C.

Experimental Procedures

After oil saturation, high- and low-permeability cores connected in parallel were waterflooded with NaCl-saturated brine. The purpose of the initial waterflooding step was to reduce oil saturation to represent a reservoir with a watered-out channel in the high-permeability layer. For coreflood number 1 with a permeability ratio of 10, the injection rate was 1.3 ft/d (0.4 m/d). Waterflooding was continued until total oil production from both cores decreased to a water-oil ratio of 20 with the fluid production ratio increasing from 20 to 100. Initial oil recovery of OOIP was 36% from the sandpack and 7% from the lower permeability core or 27% of the OOIP. After the initial waterflood, ethanol was injected as two equal slugs for a total of 0.046 PV. Each alcohol slug was alternated by the same slug size of NaCl-saturated brine, and the cores were shut-in several days to allow for salt precipitation. Then brine was injected at about 0.6 ft/d (0.18 m/d) to determine the effect of salt precipitation on oil recovery. Figure 1 shows oil production and water-oil-ratio history for coreflood 1. The permeability ratios for corefloods 2 and 3 were 3.3 and 5.0.

Since the brine permeability ratios were lower, initial waterflooding was discontinued when the water-oil ratio from the high-permeability core reached 20. The same experimental procedures were followed except ethanol was injected as three slugs. An injection rate of about 1 ft/d (0.305 m/d) was used for waterflooding and about 1.3 ft/d (0.40 m/d) for ethanol injection for these two experiments. The volume of ethanol injected for corefloods 2 and 3 was 0.064 and 0.088 PV, respectively. Further details of oil saturations and injection rates are listed in Table 1. Figures 2 and 3 show oil production and water-oil history for corefloods 2 and 3.

Results of Parallel Coreflooding

As shown in Fig. 1, after ethanol treatment, the water-oil ratio decreased sharply for coreflood 1 from about 15 to 1. Alcohol-induced salt precipitation improved oil recovery from 7 to 42% of the oil present in the low-permeability core. This was 12% of OOIP additional oil production when the experiment was terminated at water-oil ratio of 15.

TABLE 1
Core and Alcohol-Injection Data for Parallel-Coreflood Experiments

Parallel coreflood number	Test 1		Test 2		Test 3	
	Permeability		Permeability		Permeability	
Core type	high	low	high	low	high	low
	Sandpack	Berea	Berea	Berea	Berea	Berea
Core length, cm	27.3	29.3	26.7	29.1	26.7	26.8
Porosity, %	35.4	19.2	23.3	19.2	23.0	18.9
Permeability, md	2950	300	1130	340	730	145
Pore volume, mL	110.5	64.6	70.7	64.2	70.2	57.6
Original oil-in-place (OOIP), mL	92.4	40.5	47.0	41.2	48.6	38.0
Initial oil saturation, %	83.6	62.8	66.5	64.2	69.2	66.0
Oil saturation after initial waterflood, %	47.4	55.7	23.1	52.7	26.8	55.5
Oil saturation after salt precipitation and waterflood, %	45.9	20.4	17.1	22.0	26.0	19.9
Parallel cores total PV, mL	175.1		134.9		127.8	
Permeability contrast	≈10		≈3		≈5	
Number of ethanol slugs	2		3		3	
Ethanol injection total volume (% of PV)	4.6		6.4		8.8	
injection rate, ft/d (m/d)						
before alcohol	1.27 (0.39)		0.93 (0.28)		0.99 (0.30)	
alcohol slug	1.91 (0.58)		1.25 (0.38)		1.31 (0.40)	
after alcohol	0.64 (0.20)		0.93 (0.28)		0.99 (0.30)

Fig. 1 Production history for coreflood 1.

Corefloods 2 and 3 also showed that alcohol-induced salt precipitation resulted in permeability modification and improved sweep efficiency. For coreflood 2 (Fig. 2), oil recovered from the low-permeability core increased from 11 to 42%, or an additional increase of 18% of the OOIP. Figure 3 also shows a sharp decline in the water-oil ratio after alcohol injection. Salt precipitation for coreflood 3 resulted in 16% additional recovery of the OOIP.

The fluid production ratio shown in Fig. 4 indicated that at least 90% of the injected fluid flowed into the high-permeability core during ethanol injection. Therefore, a larger fraction of injected alcohol entered into the high-permeability core which resulted in greater salt precipitation and a significant permeability reduction in the more permeable core. After salt precipitation (Fig. 4) a substantial amount of the injected fluid was diverted from the high-permeability core to the low-permeability core. After alcohol injection, the fluid production ratio between the high- and low-permeability cores was reduced from about 100 to 0.5. Fluid production ratios changed from 10 to 1 for coreflood 2, and from 23 to 0.5 for coreflood 3. Also, the injection pressure increased

Fig. 2 Production history for coreflood 2.

Fig. 3 Production history for coreflood 3.

Fig. 4 Fluid production ratio of high- to low-permeability cores for corefloods 1 to 3.

from about 2.7 psi (18.6 kPa) to 20 psi (138 kPa) for coreflood 2, and from 2.6 psi (17.9 kPa) to 30 psi (207 kPa) for coreflood 3.

The permeability modification in the high-permeability core resulted in fluid diversion into the low-permeability core and improvement in system sweep efficiency. Before water breakthrough in the low-permeability core, fluid diversion caused a water-oil ratio reduction of less than 1 for the three coreflood experiments.

Oil Recovery with Salt Precipitation and CO₂ Displacement

Experimental Conditions

Gas floods with CO₂ were performed to test oil recovery of alcohol-induced salt precipitation. The Berea core used in these experiments was 5.1 cm in diameter with a length of 56.2 cm. The core had a porosity of 22%. Prior to gas injection, the brine-saturated core was flooded with North Burbank crude oil with a 39.5 API gravity. Following oil saturation, the core was flooded with brine to obtain a core with a watered-out oil saturation. Coreflooding conditions

were at a temperature of 65° C and a pressure of 1,200 psi (8.28 MPa). At these conditions CO₂ was not miscible with the crude oil. A series of tests were conducted on the same core. After each test, the cores were cleaned and flushed with a series of solvents including Stoddard solvent, normal propyl alcohol, acetone, and brine.

For comparison of oil recovery, two CO₂ floods were conducted without salt precipitation or ethanol injection. Because ethanol was used in the salt precipitation method, a CO₂ displacement test was conducted to determine if ethanol injection without salt precipitation resulted in additional produced oil. For the ethanol injection test, two 0.075 PV (19 cm³) slugs of ethanol were injected. Each ethanol slug was chased with an equal volume of 2% KCl. A low-concentration brine was used to minimize salt precipitation, and KCl was used to reduce swelling of clays in the core.

Another CO₂ flood was made to test the effect of salt precipitation on oil recovery. A 10% NaCl brine was used for core saturation and flooding. Two 10.5 cm³ slugs of ethanol were injected for the salt precipitation experiment. The total quantity of ethanol was 0.083 PV. Each ethanol slug was followed by an equal volume of NaCl-saturated brine. A small quantity of fresh water (1.8 cm³) was injected preceding each brine and alcohol injection to reduce precipitation of salt in the core inlet and injection tubing. This was accomplished by inserting a 1.8 cm³ loop filled with fresh water between the core inlet and brine or alcohol injection. Following brine and alcohol injection, the core was shut-in for 5 days to allow for salt crystal growth and increased crystal size¹ prior to initiating the CO₂ flood.

Results of Coreflooding Tests with CO₂

The results of oil recoveries for CO₂ floods are shown in Table 2. Comparison of these results with and without salt precipitation indicated the quantity of produced oil was approximately 40% higher or about 12% additional recovery of the OOIP. Also, to a lesser extent, some additional oil recovery was indicated for the alcohol injection flood. The alcohol required to induce salt precipitation was at least partially responsible for increased oil recovery. The alcohol could have reduced the interfacial tension between the brine and oil resulting in greater oil mobilization and higher oil production. Additionally, precipitated salt could have partially plugged the more permeable channels in the watered-out core diverting

TABLE 2
Comparison of Oil Recovery for CO₂ Floods and CO₂ Floods With Ethanol Injection and Salt Precipitation

Coreflood Test	OOIP, mL	Oil remaining in core, mL	Produced oil, mL	Oil recovery %
CO ₂ flood	111.0	77.1	33.9	30.5
CO ₂ flood with 0.083 PV ethanol and saturated brine	109.5	64.5	45.0	41.1
CO ₂ flood with 0.12 PV ethanol	109.9	72.4	37.5	34.1
CO ₂ flood	108.4	79.4	29.0	26.8

subsequent CO₂ flooding to highly saturated less permeable areas of the core, thereby improving sweep efficiency and increasing oil production.

These experiments were conducted with a relatively high-permeability (0.5 D) and homogeneous Berea core. Only a limited number of tests were performed, and further experiments are necessary to confirm these results. However, greater oil recovery was indicated by the salt precipitation method. Profile modification with improved sweep efficiency was indicated even in this core with relatively uniform permeability. Previously, as stated in this report, waterflooding experiments showed profile modification and fluid flow diversion was achieved in parallel cores. Even greater sweep efficiency and higher oil production may be possible for this method with CO₂ floods in nonuniform or layered rocks with contrasting permeabilities.

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THERMAL RECOVERY— SUPPORTING RESEARCH

THERMAL PROCESSES FOR LIGHT OIL RECOVERY

**Cooperative Agreement DE-FC22-83FE60149,
Project BE11A**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$300,000**

**Principal Investigator:
David K. Olsen**

**Project Manager:
Thomas B. Reid
Bartlesville Project Office**

Reporting Period: April 1 - June 30, 1993

Objectives

The FY93 objectives of this project are (1) to analyze planned tasks in this project to ensure they meet environmental, safety and health requirements; (2) to assess

the thermal research performed at NIPER over the past 10 years; (3) to develop procedure and apparatus for measuring dynamic saturation changes in steamfloods at field conditions using X-ray and CT scanning that incorporate temperature and pressure measurements to calibrate a numerical simulator for predictive purposes; (4) to conduct laboratory research in support of Naval Petroleum Reserve No. 3 (NPR-3), Teapot Dome (Wyoming) field light oil steamflood; and (5) to participate in the Annex IV meetings conducted by the DOE and the Venezuelan Ministry of Energy and Mines.

Summary of Technical Progress

This quarter SPE paper 25786, Case History of Steam Injection Operations at Naval Petroleum Reserve No. 3, Teapot Dome Field, Wyoming: A Shallow Heterogeneous Light-Oil Reservoir,¹ was accepted for publication in an SPE journal.

The operating manual,² for the software developed for automation of the steamflood laboratory was the focus of this quarter's research. The software was highlighted in the last quarterly report.³ The software was developed as general laboratory operating software that can be customized to individual laboratory or pilot plant applications. This software is an add-on to the National Instruments™ LabVIEW 2®, a high-level object-oriented dataflow language.³ LabVIEW 2's visual object oriented

programming environment allows users to develop their own automation program. However, some familiarity with the language is a prerequisite for effectively using LabVIEW 2. Users can directly configure much of the software to meet many automation needs in real-time by following a few simple steps. Example problems and solutions are included in the manual. The software is useful for laboratories and pilot plants where instrumentation requirements frequently change.

This software is expandable to allow for future enhancements. It offers real-time data, graphics, and video display capabilities, along with editing and adjustment features. The software offers instrument control by most standard methods. Warning and error recovery expert systems are other useful features. The software sends sound and text warnings to any authorized user on the network, and if no corrective action is taken in due time, it acts on a built-in logic to safely handle dangerous

situations. The software can be set to prohibit users from making illogical decisions, e.g., running a pump while an in-line valve is closed or there is no fluid in the pump's feed-tank.

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THERMAL PROCESSES FOR HEAVY OIL RECOVERY

Cooperative Agreement DE-FC22-83FE60149,
Project BE11B

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$200,000

Principal Investigator:
Partha Sarathi

Project Manager:
Thomas B. Reid
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objectives

The FY93 objectives are (1) to analyze the NIPER heavy oil data base to screen Texas Gulf Coast reservoirs for priority ranking, (2) to collect reservoir data for the most promising reservoirs, and (3) to conduct simulation studies to determine the applicability of thermal EOR techniques in the most promising heavy oil reservoirs in the Texas Gulf Coast area.

Summary of Technical Progress

Assessment of the Past NIPER Thermal EOR Research Program

The objective of this task is to review objectively the thermal EOR research performed at NIPER over the past 9 years and recommend future direction for the program. A topical report detailing the assessment (NIPER-675) was delivered to BPO and published as a DOE report.

Evaluation of the Steamflood Potential in Texas Gulf Coast Heavy Oil Reservoirs

Several steamflood simulation runs were performed in Taylor-Ina field in Medina County, Texas, to assess the feasibility of steamflooding this thin-pay, low-permeability reservoir. The reservoir grid description and the rock-fluid properties were previously reported.¹

One-fourth of a 5-spot pattern of a 2-acre area was considered for simulating a steamflood. The dual porosity model in the STARS simulator was used to represent the hydraulic fracture. For an injection well, the maximum injection pressure was limited to 1,000 psi, and the bottomhole steam quality was assumed to be 70%. The maximum steam injection rate was limited to 400 bbl/d.

Numerical simulation of steamflooding in Taylor-Ina field indicates that it is technically feasible to steamflood this field, but the economics appear to be nonattractive at the current heavy oil price of \$15/bbl. For the pattern area studied, a steamdrive using vertical wells recovered 54% of the oil-in-place (OIP) at a peak production rate of 100 bbl/d. The cumulative steam-oil ratio at the end of 1,400

days was at 0.14. These performance indicators suggest that steamflooding in Taylor-Ina field can be a technical success. However, simplified economic calculations indicated that a project may not be economical at the current oil price.

As an alternative to steam injection, the feasibility of an immiscible CO₂-waterflood process in this thin, low-permeability reservoir was investigated.

Numerical simulation of an immiscible CO₂-waterflood was conducted in a 1/4th element of symmetry of a 9-acre 5-spot pattern. A 11x11x3 grid and similar reservoir properties, as mentioned in the previous quarterly report,¹ were used. Water was injected in the beginning for 60 days to increase the pressure of the reservoir. Pressure in the near wellbore area increased from 200 psi in the beginning to 780 psi. Then gas and water were injected in 5 cycles and finally water was injected continuously. In each cycle of 30 days, gas and water were injected for the same time period of 15 days. The maximum rate for gas and water was limited to 200 mcf/d and 400 bpd, respectively. Figures 1 and 2 show histories of rates of gas and water injection and oil production, WOR, and GOR. Figure 3 shows cumulative oil production and CGOR (cumulative gas oil ratio, mcf/stb) histories. Gas and water were injected such that bottomhole injection pressure remained below the formation fracture pressure (1,000 psi). The full rate of gas injection was achieved in all the cycles, but the rate of water injection started decreasing from the third cycle. The final rates at the end of third, fourth, and fifth cycles were 230, 200, and 179 bpd, respectively. The rate of water injection reached a minimum value of 69 bpd at 1,700 days and then increased to 95 bpd at 5,000 days.

Oil production reached a maximum of 10 stb/d at 3,900 days and then decreased to 8 stb/d at 5,000 days. The WOR was about 5 for 230 days and then increased to 11 at 5,000 days. The cumulative results were based on a final time of 5,000 days. The total amounts of water and gas injected were 430 mstb (2.15 PV) and 15,000 mcf. The cumulative oil production and CGOR were 36,624 stb (33% of OOIP) and 0.4 mcf/stb, respectively. The recovered oil was obtained just after primary and not after waterflood. The oil recovery was good, possibly because the pattern area was small and the wells were very well fractured which

Fig. 1 Water and gas injection rate histories.

Fig. 2 Oil production rate, WOR and GOR histories.

Fig. 3 Cumulative oil production and CGOR histories.

resulted in very good areal sweep efficiency. The operating cost and net revenue were \$5.88 and \$150,811, respectively. Considering a discount rate of 10%, the present value of the net revenue was only \$51,000.

Assessment of Mobil's Steamflood Predictive Model

A personal computer based steamflood performance model developed by Mobil E&P U.S. Inc. was evaluated by comparing its predictive ability with the performance of 12 steamdrive projects. This included eight California reservoirs and four non-California reservoirs. No attempt was made to history match the field production data. Instead, the model was evaluated by comparing its production trend with that of the field and checking as to whether the model qualitatively exhibited the same trend as the field. The economics option of the model was not evaluated. Harrigal and Wilcox² have described the features of the model.

With minor tuning of the selected parameters, the model was able to predict the production trend of California reservoirs, but was not able to adequately predict the production behavior of the non-California reservoirs. Two reasons may be cited for the model's less-than-satisfactory

predictive ability with respect to non-California steam projects.

The various correlations used in the model to describe oil production and other performance indicators were developed using the reservoir characteristics and operating conditions of California steamdrive projects. Hence, the mathematics was able to describe the dynamics of California steam projects better than the non-California projects. Also, most steam injection projects implemented in the non-California reservoirs were designed to accommodate the unique futures of those reservoirs. For example, in Slocum field, Anderson County, Texas, steam is injected into the aquifer and the oil is mobilized principally by the conduction of heat from the aquifer. Since the model does

not account for this unique operating feature, its predictive capability is inadequate to describe the performance of such projects.

References

1. National Institute for Petroleum and Energy Research. *Quarterly Technical Report for Jan. 1-Mar. 31, 1993, Vol. II Energy Production Research*, DOE Report NIPER-684, June 1993, p. 18.
2. R. L. Harrigan and G. G. Wilcox, *An Improved Steamflood Analytical Modeling Tool: Updating Old Methodologies with New Approaches to Increase Engineering Productivity*. Presented at the seventh SPE Petroleum Computer Conference, Houston, TX, July 19-22, 1992. SPE paper 24434.

FEASIBILITY STUDY OF HEAVY OIL RECOVERY IN THE MIDCONTINENT REGION: OKLAHOMA, KANSAS, AND MISSOURI

**Cooperative Agreement DE-FC22-83FE60149,
Project SGP37**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Apr. 1, 1990
Anticipated Completion: May 1, 1994
Funding for FY 1993: \$293,000**

**Principal Investigator:
David K. Olsen**

**Project Manager:
Thomas B. Reid
Bartlesville Project Office**

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this nationwide heavy oil feasibility study are (1) to investigate from publicly available data the known heavy oil resources, (2) to screen this resource for potential thermal or other enhanced oil recovery (EOR) techniques, and (3) to evaluate various economic facets that may have an impact on the expansion of heavy oil production—refining, transportation, environmental, etc.

Summary of Technical Progress

This quarter, information continued to be compiled on the Nation's heavy oil (10°-20° API) resource as part of a relational database, and a topical report¹ was completed that details the computer modeling effort to estimate the Nation's heavy oil resource and the estimated recovery using various recovery technologies. The computer model

that was used is an adaptation of the DOE TORIS model derived from the National Petroleum Council (NPC) 1984 EOR study.² The results of this study were summarized last quarter.³

Preliminary information on heavy oil reservoirs was selected in 1992 and 1993 for analysis from the information being collected by this project. Each set of data was run through the TORIS screening models to determine oil price sensitivities. The results were segregated by lithology, location, environmental deposition, and profitability. Although potential EOR estimates were obtained using preliminary reservoir data, results clearly indicate potential for heavy oil recovery significantly above current production at 1993 oil prices. Most of this potential is for steam recovery of oil in California. Another significant EOR opportunity uses advanced alkaline/surfactant/polymer (ASP) processes that recover oil more economically or from different reservoirs than steam. The potential for in situ combustion is usually in the same reservoirs as steam recovery but are less profitable and have lower oil recovery efficiency. The following are specific results from the computer modeling task:

- A review of the DOE EOR Project Database indicated that the state-of-the art for steam and in situ recovery processes has improved since the screening criteria for EOR processes were originally coded into the computer tools in 1983. The improvements in the technology were included in the preprocessor programs DEFLTAL and ROBLT which results in more reservoirs passing through the screening process to the economic and production predictive programs.
- The economics of the steamflood predictive model was updated to a \$20 base oil price referenced to 40° API gravity oil and 1991 operating cost.^{1,2}
- The data available for the 1992 model runs represented 50.5 billion bbl of original-oil-in-place (OOIP) in 205 reservoirs in the lower 48-states. Another 25 billion bbl OOIP in three reservoirs were defined in Alaska that have marginally acceptable rates of return with oil prices above \$30/bbl with advanced steam technology. The TORIS heavy oil reservoir data were

used for 154 reservoirs representing 64.3 billion bbl of OOIP (including 25 billion bbl in Alaska), and the remainder were updated information on Midcontinent, Wyoming, and Permian Basin heavy oil reservoirs collected as part of another task of SGP37.

- Results of the 1992 model runs showed a large potential for steam recovery of heavy oil—30 to 50 years of production with implemented technology and 40 to 120 years of production with advanced (plus implemented) steam recovery technologies at current production rates of 0.5 million bbl/d. The oil price range for the analysis was \$17/bbl to \$32/bbl for an average wellhead price of 40° API gravity benchmark crude. The potential recovery from in situ combustion ranged from 0.1 to 3.7 billion bbl. Estimates of advanced ASP processes indicate recovery potential of 0.1 to 1.4 billion bbl. The potential for each process is the potential for the entire resource without regard to eliminating duplicate application of the methods to a reservoir.
- The data available for the 1993 model runs represented 68.6 billion bbl of original-oil-in-place (OOIP) in 536 reservoirs in the lower 48 states. The information on these heavy oil reservoirs was collected as part of another task of SGP37 and not specifically for model runs. Modifications were made to the information where the data caused unreasonable estimates of EOR potential.
- Results of the 1993 model runs showed a large potential for steam recovery of heavy oil—50 to 70 years of production with implemented technology and 70 to 100 years of production with advanced (plus implemented) steam recovery technologies at current production rates of 0.5 million bbl/d. Roughly 10% of the potential for advanced steam processes could be more profitably produced by advanced in situ combustion or ASP processes at the reference oil price of \$20/bbl but in all cases steam processes would recover more oil than the competing process. The oil price range was \$17/bbl to \$32/bbl for an average wellhead price of 40° API gravity benchmark crude in this analysis. The potential recovery from in situ combustion ranged from 0.6 to 4 billion bbl, but 90% of this is more economically recovered by steam methods at the \$20/bbl scenario. Estimates of advanced ASP processes indicate recovery potential of 0.3 to 1.4 billion bbl; 90% was more profitable than steam or in situ processes at the \$20/bbl scenario.

References

1. National Institute for Petroleum and Energy Research. *Quarterly Technical Report for Jan. 1-Mar. 31, 1993, Vol. II Energy Production Research*, DOE Report NIPER-684, June 1993, pp. 19-21.
2. National Petroleum Council, *Enhanced Oil Recovery*, 1984.
3. J. F. Pautz, *Review and Update of Computer Tools and Determination of the EOR Potential of the Domestic Heavy Oil Resource*. DOE Report NIPER-692, 1993.

SIMULATION ANALYSIS OF STEAM-FOAM PROJECTS

Cooperative Agreement DE-FC22-83FE60149,
Project SGP58

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: June 1, 1992
Anticipated Completion: May 31, 1994
Funding for FY 1993: \$321,000

Principal Investigator:
Partha Sarathi

Project Manager:
Thomas B. Reid
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this research program are: (1) to conduct a study on the viability of the steam-foam process by analyzing data from selected completed steam-foam projects and (2) to assess under what conditions the process is likely to succeed, both technically and economically.

Summary of Technical Progress

Foam History Match

History-match runs were performed during this quarter in an attempt to match the general features of Chevron's Section 26-C steam-foam pilot data. The reservoir grid description and the surfactant properties used in the simulation were previously reported.^{1,2} Although we were able to obtain a good match of oil production trend, we were less than successful in capturing the observed pressure and temperature rise simultaneously. Our attempt to match both temperature and pressure by adjusting the surfactant adsorption rate and residual gas saturation caused oil production rate to deviate from the field value. Although various combinations of parameters all yielded an acceptable history match, the results indicate that quantitative prediction of observed behavior is less likely due to the lack of complete field data and the basic assumptions of the foam model employed.

Although the overall history match was less than satisfactory, the STARS simulator with its empirical foam modeling capabilities was able to capture many of the field observations. Hence, it was concluded that the simulator is adequate to analyze and predict long-term steam-foam application performance.

"What-if" simulation (sensitivity study) runs are currently being conducted to establish the key parameters influencing the steam-foam performance characteristics and

to identify steam-foam process problems relevant to specific reservoir settings. Sensitivity of steam-foam performance to surfactant concentration and surfactant loss due to thermal degradation, adsorption at the rock surface and partitioning into the oil phase was made. The results are currently being analyzed. Preliminary analysis indicate that while surfactant loss hinders the propagation of foam, the effect from loss of surfactant on oil recovery appears to be minimal. Additional sensitivity runs are planned for the next quarter.

References

1. National Institute for Petroleum and Energy Research. *Quarterly Technical Report for Oct. 1-Dec. 31, 1992, Vol. II Energy Production Research*, DOE Report NIPER-671, March 1993, p. 21.
2. National Institute for Petroleum and Energy Research. *Quarterly Technical Report for Jan. 1-Mar. 31, 1993, Vol. II Energy Production Research*, DOE Report NIPER-684, June 1993, p. 21.

ORGANIZATION OF UNITAR 6TH INTERNATIONAL CONFERENCE ON HEAVY CRUDE AND TAR SANDS

**Cooperative Agreement DE-FC22-83FE60149,
Project SGP77**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: June 1, 1993
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$75,000**

**Principal Investigator:
David K. Olsen**

**Project Manager:
Thomas B. Reid
Bartlesville Project Office**

Reporting Period: April 1 - June 30, 1993

June 10-11, 1993, by DOE/BPO and the UNITAR CENTRE (United Nations Institute for Training and Research Centre for Heavy Crude and Tar Sands), and NIPER. The purpose was to produce a draft agreement between DOE and UNITAR CENTRE to host the conference, select the conference dates of February 12-17, 1995, structure the conference organizing committee, and develop a budget for the conference. Some of the tasks that UNITAR and NIPER can conduct were identified to help the conference organizing committee.

Background information on previous attempts to plan and organize the UNITAR 6th International Conference on Heavy Crude and Tar Sands were assembled and analyzed. Based on the analysis, a draft budget was developed from the estimated number of papers and technical sessions anticipated, information from previous conferences, and potential vendors supplying printing and catering services. The budget reflects input from the 4th International Conference on Heavy Crude and Tar Sands held in Canada in 1988 and the 5th International Conference on Heavy Crude and Tar Sands held in Venezuela in 1991.

Subcommittees necessary to help the conference organizing committee were defined, and some of the potential subcommittee members have been identified. Technical sessions, luncheon, and social function attendance have been estimated and sent to prospective Houston hotels to identify space requirements and costs such that bids from hotels can be examined by the conference organizing committee. A listing of potential technical session chairmen has been compiled to supplement UNITAR listings of previous meeting volunteers. The conference budget requires significant volunteer effort and industrial support to remain within budget.

Weekly reports on the progress of the organizational efforts have been forwarded to BPO.

Objectives

The objective of this project is to assist DOE in planning and organizing the UNITAR 6th International Conference on Heavy Crude and Tar Sands scheduled for February 1995, in Houston, Texas.

Summary of Technical Progress

NIPER assisted DOE in determining previous organizational efforts that have been made by various groups for the United States (DOE) to host the UNITAR 6th International Conference on Heavy Crude and Tar Sands. A meeting was held in Bartlesville, Oklahoma,

GEOSCIENCE TECHNOLOGY

THREE-PHASE RELATIVE PERMEABILITY RESEARCH

**Cooperative Agreement DE-FC22-83FE60149,
Project BE9**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract date: Oct. 1, 1985
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$340,000**

**Principal Investigator:
Dan Maloney**

**Project Manager:
Rhonda Patterson Lindsey
Bartlesville Project Office**

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this project are (1) to improve the reliability of laboratory measurements of three-phase relative permeability for steady- and unsteady-state conditions in core samples; (2) to investigate the influence of rock, fluid, and rock-fluid properties on two- and three-phase relative permeabilities; and (3) to expand the state-of-

the-art for measuring relative permeabilities at higher temperatures and pressures.

Summary of Technical Progress

Oil/brine relative permeability tests for Almond formation sample 4953 were reported during the last quarter. The tests were performed at 49° C. The sample was subjected to 7 MPa confining pressure. The results suggested that the wetting phase relative permeability increased when the temperature was raised. The test was repeated during this quarter. Results have not been analyzed yet. Capillary pressure tests were performed on Fontainebleau sandstone samples.

After discussions with consortia members early in the project year, the suggestion to use a fluid system composed of two compounds was adopted. 1-bromopropane was selected as one of the fluids because of its X-ray absorption characteristics. After an initial comparison of PVT (pressure, volume, temperature) properties for methane, ethane, propane, and decane, propane was selected to be the second component of this binary fluid system.

Figure 1 shows results from 1-bromopropane laboratory PVT measurements. Measurements were limited to temperatures below 180° C. Insufficient data were available from the laboratory measurements to predict the characteristics of the propane/1-bromopropane mixture. Therefore, actual laboratory measurements were required. The decision was made to test a 1:1 molar mixture of propane and 1-bromopropane.

Several attempts to produce liquid propane by changing the propane pressure at ambient temperature were

unsuccessful. Liquid nitrogen was then employed to cool a receiving cylinder, reducing the cylinder temperature enough to liquify propane. The cylinder was used to transfer liquified propane into a 500 cm³ accumulator and into the PVT cell at a pressure of 1140 kPa. The volume of 1-bromopropane required for a 1:1 molar mixture was then pumped into the PVT cell. 1-bromopropane is liquid at ambient temperature and pressure conditions.

PVT characteristics of the 1:1 molar mixture of propane and 1-bromopropane were measured at five temperatures ranging from 22° to 68° C. To prevent experiments from becoming too complicated, maximum temperature and pressure limits of 7 MPa and 66° C were selected. Bubble points were measured visually for each temperature. Results are shown in Fig. 2. Bubble points were normally obtained from graphs by plotting pressure versus volume. The bubble point for 68° C was measured by both visual and pressure/volume graphical methods for comparison. Visual bubble point observations yielded higher bubble point pressures than those determined with graphical techniques as shown in Fig. 3. This result should be kept in mind when experiments are performed using live fluids. It may be prudent to keep the pressure at least 20% higher than the bubble point pressure when a gas phase cannot be tolerated.

After measuring the bubble point at a test temperature, the pressure was reduced and the resulting gas volume percentage was measured. Gas and liquid volumes were measured at four pressures for each temperature condition. Results are shown in Fig. 4. Gas volumes greater than 60% of the total fluid volume could not be achieved during these tests because of volume and pressure constraints. For future work, higher gas saturations should be measured. To achieve 100 % gas, pressures approaching vacuum will probably be required.

The 1-bromopropane stays mostly liquid throughout the range of pressures and temperatures selected for this project. This facilitates X-ray saturation measurements.

A small change in pressure causes a large change in gas saturation as shown in Fig. 4. Depending on experimental constraints, this may be viewed as an advantage or disadvantage. During flow tests with this fluid, pressure drops across the length of the rock sample must be kept low in order to maintain uniform gas saturations.

Laboratory flow tests using the propane/1-bromopropane fluid system were designed. Tests should start during the next reporting period. The most difficult aspects of the tests relate to gas injection and pressure maintenance.

Steady-state oil/brine, gas/brine, and gas/oil tests were completed on a sample of the Fontainebleau sandstone. These results will be useful for comparison with relative permeability results using the propane/1-bromopropane fluid system. Two samples of Fontainebleau sandstone were prepared for unsteady-state flow tests. Unsteady-state data will be used to test the simulator being developed as part of the project. Capillary pressure characteristics of the Fontainebleau sandstone were measured during centrifuge tests.

The Gateway 2000 Model 486DX2/66V computer system was received at the beginning of the reporting period. This computer is equipped with 32 MBytes of memory, a 340 MByte hard drive, and a very fast video adapter with a 38.1 cm color monitor. The hard drive and the video adapter operate off a VESA local bus system and provide very fast response. The computer is also equipped with a CD-ROM drive and a tape-cartridge drive for backup. Two versions of the Microway FORTRAN compilers -- one for DOS extenders, and one for OS/2 2.x, have been installed on the computer. These have been used to compile a version of the BOAST simulator for both systems. Some time was required to modify the source code to obtain a working simulator.

Fig. 1 Bubble point data for 1-bromopropane.

Fig. 2 Bubble point data for 1-bromopropane (1-BrC3), propane, and a 1:1 molar mixture of the two.

Fig. 3 VT data for the 1:1 molar mixture of propane and 1-bromopropane at 68°C.

Fig. 4 PVT results for a 1:1 molar mixture of propane and 1-bromopropane.

The compiled BOAST simulator has been tried on several 1D and 2D simulations. On 2D data sets involving approximately 3000 grid blocks, the simulator takes about 30 minutes to perform 600 trials before reaching terminating conditions. For a 1D data set involving 40 grid blocks, the simulator took 33 seconds to do approximately 1000 trials before reaching an endpoint. During this 33 second run, the simulator output 36 data files showing the 1D oil, water, and gas saturations and how the flood front traversed the length of the model during the simulation. The simulator will be used to study 1D and 2D models based on permeability, porosity, capillary pressure, and saturation distributions representative of real rock systems under study in the laboratory.

One-dimensional simulations were performed using the BOAST simulator to study the dependence of waterflood-front movement on relative permeability curve shapes. This work was performed as a precursor to trying to analyze actual coreflood data with the simulator. Relative permeability curve end-points were the same in each case. Various runs were performed first by varying the brine relative permeability curve while the oil curve was maintained constant and subsequently by keeping the brine curve constant while the oil curve was changed. The computer speed was better than expected, allowing a number of simulations to be performed in the time that the older machines would have required to perform only one simulation. Results are being analyzed.

IMAGING TECHNIQUES APPLIED TO THE STUDY OF FLUIDS IN POROUS MEDIA

Cooperative Agreement DE-FC22-83FE60149,
Project BE12

National Institute for Petroleum
and Energy Research
Bartlesville, Oklahoma

Contact date: Oct. 1, 1987
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$350,000

Principal Investigator:
Liviu Tomutsa

Project Manager:
Bob Lemmon
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this project are (1) to develop and correlate reservoir engineering parameters from petrographic image analysis, computed tomography (CT) scanning, and nuclear magnetic resonance imaging (NMRI); (2) to investigate the applicability of imaging technologies in the development of scale-up procedures from core plug to whole core to interwell scale; (3) to plan, review, and participate in the research through the Work-For-Others program and to provide for effective technology transfer; and (4) to strongly encourage collaborative research by industrial participants.

Summary of Technical Progress

As part of the experimental investigation in the scaling up of the relative permeability in a heterogeneous rock, the brine and oil relative permeability have been measured in

imbibition and drainage steady-state cycles for a Tallant sandstone sample. The experimental set up for relative permeability measurements uses CT scanning for saturation measurements and a computer data acquisition system for pressure measurements. Constant pressure drop across the sample over time is the first indication of reaching steady-state. Consecutive CT scans are used to further verify the steady-state conditions as shown by a constant longitudinal oil and brine saturation profile. Also, relative permeability experiments have been initiated on a Tallant 1-in.-diameter, 2-in.-long plug. The relative permeability values normalized to the absolute brine permeability are shown in Fig. 1. Analysis of data indicates no significant hysteresis between the imbibition and drainage cycles. The points in the figure are taken at fractional brine flow rates of 0.0, 0.05, 0.1, 0.2, 0.4, 0.7, 0.9, 1.0. Each point is taken after 6 pore volumes of total fluid flow at the respective fractional flow. A flow rate of 18 mL/hr corresponding to a front advancement of 2 ft/d was used. The brine was tagged with 7% NaI to ensure the appropriate X-ray attenuation contrast between it and the oil. The oil used was Soltrol with a viscosity of 26 cP. The drainage cycle was performed after the imbibition cycle when fractional brine flow reaches 100%. The actual spatial oil saturation distribution within the sample for the drainage cycle is shown for a vertical crosssection in Fig. 2, and is similar to that reported last quarter at equivalent brine fractional flows for the imbibition cycle. Each view corresponds to each of the points on the relative permeability curves. The brine fractional percent flow is indicated at the left of each image. The contrast in oil saturation between the ripples and the clean sand is the most pronounced at high oil saturation and the least pronounced at low oil saturation.

As the brine fractional flow starts to decrease, the gravitational effect becomes apparent with the oil saturation being higher near the top of the sample in the initial stages of oil flow. At the lowest brine flow fraction, the gravitational effect disappears as shown in the bottom slice of Fig. 2. In Fig. 3, longitudinal saturation profiles

Fig. 1 Steady-state relative permeability curves for brine and oil in Tallant sandstone sample. Shown are the imbibition and drainage cycles. Values normalized to single-phase brine permeability.

are shown for brine fractional flows corresponding to the points on the relative permeability curves. The saturation values were generated by averaging the saturation for each of the 63 crosssections (slices) perpendicular to the flow direction generated by CT scanning. A saturation gradient between inlet and outlet is present throughout the entire cycle. The saturation variation is the strongest close to the sample ends and is only a few percent between the pressure ports. This results from the presence of an initial nonuniform oil saturation for the sample. To show the dependence of the oil saturation on rock properties, saturations and porosity are plotted in Fig. 4 along a vertical line situated in the center of the sample, at the intersection of a longitudinal plane (slice 108) and crosssection plane (slice 32). At the initial oil saturation, and for most of the brine fractional flows, a significant dependence of the saturation on the porosity is observed, with contrasts in oil saturation between the high and low porosity zones as high as 25%. At residual oil, the saturation dependence on rock properties becomes much less significant. This is similar to the results reported last quarter for the imbibition cycle.

To improve the modeling of two-phase fluid flow in the heterogeneous rock sample studied, simulations were run using capillary pressures in the laboratory-scale BOAST simulator. Capillary pressure is the difference between the two pressures, P_o , pressure in the non-wetting fluid (oil), and P_w , pressure in the wetting fluid (water) respectively. Thus, $P_c = P_o - P_w$ gives positive capillary pressure in a water-wet system. Figure 5 shows the low and high capillary pressure/water saturation curves used in the simulations.

The capillary pressure in a capillary tube, P_c , is defined

$$\text{as: } P_c = P_o - P_w = \frac{\sigma_{ow} \cos \theta}{r}$$

where σ_{ow} = interfacial tension
 θ = contact angle
 r = radius of capillary.

The factors that affect the curvature of the interface formed between two immiscible fluids within the pore space are: (1) wettability; (2) interfacial tension; and (3) pore size distribution.

Fig. 2 Oil saturation distributions in a longitudinal, vertical cross-section during steady-state drainage cycle measurements (Slice 108). The brine fractional percent flow is indicated at the left of each image.

Fig. 3 Average oil saturation along the sample during drainage cycle.

The Buckley-Leverett fractional water flow in porous rock is given by

$$f_w = \frac{q_w}{q_o + q_w} = \frac{1 + \frac{Kk_{ro}A}{q_t \mu_o} \left(\frac{\partial P_c}{\partial u} - g \Delta \rho \sin \alpha \right)}{1 + \frac{k_{ro} \mu_w}{k_{rw} \mu_o}}$$

If the gravity effect, $g \Delta \rho \sin \alpha$, is ignored this reduces to

$$f_w = \frac{1 + \frac{Kk_{ro}A \partial P_c}{q_t \mu_o \partial u}}{1 + \frac{k_{ro} \mu_w}{k_{rw} \mu_o}} = \frac{1 + \frac{k_{ro} \partial P_c}{q_t \partial u}}{1 + \frac{1}{M}}$$

where M is the mobility ratio.

Fig. 4 Porosity and oil saturation values along a vertical line (intersection of longitudinal slice 108 and transversal slice 32) at various stages during drainage cycle. The brine fractional flow is indicated in the legend.

When capillary pressure is ignored, this equation reduces to

$$f_w = \frac{1}{1 + \frac{1}{m}}$$

The results from the simulation study shown in Fig. 6 indicate that the average saturation profile has a less sharp front with capillary pressure than the case without capillary pressure. Thus, earlier water breakthrough in the displacement occurs with capillary pressure. The average velocity of the flood front at any water saturation, u , is proportional to df_w/dS_w on the plot of f_w versus S_w curves. For a miscible displacement process of mobility ratio equal to 1, the addition of capillary pressure increases the fractional water flow which in turn increases the average water velocity at the front. This behavior corresponds with the theoretical equation discussed above. It was also noted that the average reservoir pressure increases with the addition of capillary pressure in the simulation. This is the result of the total flow rate constraint applied during the simulation runs. The CT scan average saturation profile shown in Fig. 6 has a smoother front indicating the effect of capillary pressure in the porous media.

The oil saturation distribution images at 0.14 pore volume of injected water were compared using simulation runs without capillary pressure curves, simulation runs with capillary pressure curves, and CT scan images of core flood. The capillary pressure curves considered are low capillary pressure versus saturation, and high capillary pressure versus saturation. The simulator used accepts two relative permeability curves and two capillary pressure waves for the two permeability zones considered in this sample.

Using a mobility ratio of 1 and the porosity/permeability distribution from the CT scan of experimental sample, the simulation was run with 63 by 1 by 126 grid blocks subjected to specified laboratory injection and production rates. Simulation run A is with both capillary pressure

Fig. 6. Comparisons of average oil saturation at 0.14 pore volume for CT scan and simulations with and without capillary pressure.

Fig. 7 Comparisons of oil saturation at 0.14 pore volume of fluid injected for CT scan versus simulations with and without capillary pressure.

input using the low capillary pressure curve in Fig. 5. Simulation run B is with both capillary pressures input using the high capillary pressure curve in Fig. 5. Simulation run C is without the capillary pressure.

Oil saturation distributions from simulations were compared with CT scan oil saturation distributions, as shown in Fig. 7. The saturations from the simulations with capillary pressures matched the CT scan oil saturations better than those without capillary pressures for the waterflood front fingering. The simulations without capillary pressure showed better agreement with CT scans of the saturations ahead of the front. These results indicate the need to perform simulations with accurate capillary pressure values.

In an effort to correlate how oil and water behave at the pore level toward oil-wet and water-wet surfaces with their appearance in pore scale NMR images, an NMRI phantom was made using two sizes of small bore glass capillary tubing. The smaller size was 590 microns OD with a 140-micron ID while the larger size was 670 microns OD with a 210-micron ID. The larger size tubing was treated with Dow Corning 561 transformer oil to make it oil-wet by filling the tubes under vacuum with the oil and heating at 200° C for 4 hours. The smaller size tubing was cleaned with chromic acid solution to make it water-wet by filling the tubing under vacuum and letting it set in the cleaning solution for several hours. The oil-wet tubing was drained of excess oil and blotted with paper wipes several times to remove as much of the oil as possible. Some oil remained on the surface of the tubing, particularly on the inside. The water-wet tubing was rinsed in deionized water several times and dried under vacuum. The two sizes of treated capillary tubing were blended into a bundle approximately

5.3 mm in diameter by mixing them randomly and containing them with Teflon heat-shrink tubing. A section of the bundle approximately 9.5 mm long was cut and fitted with Teflon end caps using the two-layer Teflon heat-shrink tubing method used with small rock core plugs.

The phantom was saturated with brine (0.504% NaCl, 0.023% MnCl_2) under vacuum and mounted in the NMRI sample probe. Preliminary experiments showed that the 90 degree RF pulse length was 3.0 microseconds and the natural line width of the water signal in the brine was 160 Hz. An inversion recovery experiment showed the T_1 relaxation time to be 80 milliseconds. An NMR image was obtained using 8 accumulations (256 points) per scan with 256 X/Y-angles and 64 Z-angles. The echo time was 2.56 milliseconds and the NMR bandwidth was 100,000 Hz. Soltrol oil (5 cP) was then flowed through the phantom (20 PV). A standard NMR experiment revealed two distinct peaks, a higher field peak for the brine phase and a lower field peak for the oil phase. The two peaks were separated by 1,070 Hz. Two NMR images were obtained using the same parameters as above: one showing the total fluid and the second showing the oil phase. The oil phase image was obtained by using a longer echo time (15.2 milliseconds) during which time the brine signal disappeared because of its higher T_2 relaxation rate. Brine was then flowed through the phantom (20 PV) and another NMR image was obtained, using the same parameters as above, showing the residual oil phase.

Figure 8 shows a surface-rendered view of the thin layer of brine adjacent to the capillary tube surface for the brine-filled phantom. The bulk brine in the void spaces and the glass in the capillary tubes have been made transparent. The smaller bore and larger bore tubes can be clearly distinguished in the figure. However, there is no clear distinction between the behavior of the water-wet tubing and oil-wet tubing toward the brine phase. Also the surface layer has a lumpy appearance not characteristic of the smooth glass surface of both tube sizes. During the phantom preparation it was heated to more than 320° C for several minutes to shrink the outer layer of Teflon tubing. This may have caused the thin layer of 561 oil remaining on the oil-wet tubes to flow onto the other water-wet tubing. This layer of silicone oil apparently distributed itself randomly during filling and caused the lumpy appearance of the glass surface.

Figure 9 shows four cross-sectional views of the brine and two-phase fluid distributions within the phantom. View 9(A) shows the brine-filled view. Because of the different OD's of the two tubing sizes, they did not pack closely, leaving several larger voids between neighboring tubes. Also, the silhouettes of the tubes show a lumpy appearance similar to Fig. 8. View 9(B) shows the oil phase after 20 PV of oil flowed through the phantom. A few of the smaller tubes were filled with oil but most appear to contain brine which is invisible. A majority of the larger tubes are oil filled but a substantial number apparently contain brine. Some of the inter-tube voids show a lighter shading. The entire lengths of the tubes or voids were not filled with a given phase so these may be areas near the interface between an oil slug and a brine slug

within a given void. The total fluid view for the two-phase system was not shown because the chemical shift effect caused by the distinctly separate peaks for the brine and oil phases caused severe defects and distortions in the image. The 1,070 Hz difference between the brine and oil peaks was equivalent to about 3 pixels in the image and caused this distortion. View 9(C) represents the residual brine phase and was obtained by difference (A-B), allowing for the chemical shift effect. View 9(D) shows the residual oil phase after 20 PV of brine flowed through the phantom. In this view, only two of the smaller bore tubes contain oil and about 30 % of the larger bore tubes along with some of the inter-tube voids retained the oil phase.

Fig. 8 NMR image of brine-filled glass capillary tube phantom showing the surface-rendered view of the thin layer of brine adjacent to the tube surfaces. The glass and the bulk water in the void spaces was made transparent. Two sizes of tubes were used: the larger was treated to be oil-wet; the smaller was washed in acid to be water-wet. Block: 1200 microns on edge.

Fig. 9 NMR images of fluid saturation in a glass capillary tube phantom. The larger tubes were treated to be oil-wet and the smaller tubes were cleaned with acid to be water-wet. (A) Brine phase (white). (B) Oil phase (black) at residual brine. (C) Residual brine phase (white) by difference (A-B). (D) Residual oil phase (black).

The above results need to be interpreted with several cautions, one of which has already been mentioned. First, the treatment of the larger bore tubes with silicone transformer oil to make them oil-wet left a substantial amount of oil on the surface which evidently transferred to the water-wet smaller bore tubes during phantom preparation, removing most of the distinctive wettability differences sought in preparing the phantom. Teflon "Spaghetti" tubing, which can be obtained as small as 560 microns OD and 250 microns ID, will be used to construct a phantom to obtain oil-wet conditions. Teflon is strongly oil-wet and could provide a stable fractional wet

system. Second, because of the linear nature of the phantom, good access at the end caps to each tube bore or inter-tube void was not possible if the end cap was tight against the tube bundle. After the initial filling with brine under vacuum, which achieved good filling, the flow of oil or brine phases at later stages may not have accessed all the tube bores or voids. Therefore, the distribution of various phases shown in Fig. 9(B,C, or D) may not be related to the wettability of the phantom components. For a fractional wet system, both Teflon and glass tubing will be used together. The end caps will be redesigned.

RESOURCE ASSESSMENT TECHNOLOGY

RESERVOIR ASSESSMENT AND CHARACTERIZATION

**Cooperative Agreement DE-FC22-83FE60149,
Project BE1**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract date: Oct. 1, 1985
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$795,000**

**Principal Investigator:
Susan R. Jackson**

**Project Manager:
Edith Allison
Bartlesville Project Office**

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this project are (1) to develop geological and engineering methods to predict mobile oil saturation distribution and quantify reservoir architecture and flow unit geometry for application to targeted infill drilling and EOR; and (2) to synthesize reservoir and production characteristics of shoreline barrier reservoirs and to determine similarities and differences and the degree to

which information from one reservoir can be applied to another.

Summary of Technical Progress

Introduction

Major findings from a broader study addressing Task 2 of 1993 BE1 Project Plan, entitled "Summarize reservoir characteristics of shoreline deposits using Patrick Draw and Bell Creek fields as examples, and evaluate the effectiveness of various recovery methods and engineering practices in this class of reservoirs," are discussed in this quarterly report. A long-standing question within the discipline of reservoir characterization has been: to what degree do reservoirs, deposited in similar depositional environments, have similar reservoir properties, characteristics, and scale and type of heterogeneities? Information from detailed studies of two barrier island reservoirs, Bell Creek field, Montana, and Patrick Draw field, Wyoming, and outcrop exposures of the reservoir formation, conducted in this project along with information reported in the literature is being analyzed to identify the characteristics common among shoreline barrier (SB) reservoirs. The transferability of data from one shoreline barrier reservoir to another is also emphasized.

Summary of Literature Survey of Shoreline Barrier Reservoirs

NIPER-622 revised "Annotated Bibliography of Selected References on Shoreline Barrier Island Deposits with Emphasis on Patrick Draw Field, Sweetwater County,

Wyoming" was published.¹ This bibliography describes papers on ancient barrier island deposits organized by region including: Greater Green River Basin, Powder River Basin, San Juan Basin, other Rocky Mountain basins, and Gulf Coast basins. Papers on modern shoreline barrier deposits in the United States and abroad are also included. The references are listed alphabetically by authors in the appendix.

Overall Reserves and Recovery Efficiency of Shoreline Barrier Reservoirs

Three hundred and nineteen SB reservoirs are listed in the TORIS data base.² The distribution of original oil-in-place ranged from 0.5 to 1,071 MMSTB with a median of 40 MMSTB. The cumulative oil production ranged from 0.16 to 516 MMSTB with a median of 11.8 MMSTB. The median values are 27%, 16%, and 38% for the primary, secondary, and ultimate recovery factors, respectively. The above production statistics indicated good oil recovery efficiency from SB reservoirs. In comparison to other SB reservoirs, Bell Creek and Patrick Draw fields have good ultimate recovery efficiency of 53% and 47%, respectively. The good rock permeability and relatively homogeneous reservoir of Bell Creek field resulted in a successful waterflooding recovery of 37% of original oil-in-place (OOIP). In spite of the heterogeneity in the northeastern part of the reservoir, the 30% primary recovery efficiency of Patrick Draw field is attributed primarily to the production mechanism of gas cap expansion.

Variability in Facies Dimensions: the Modern and Ancient Shoreline Barrier Deposits

A compilation of the maximum facies dimensions reported in 15 references is presented in Fig. 1 and illustrates the geometry and volume differences of the facies within the barrier island system. The shoreface and foreshore facies have volumes over 10 times those of the tidal inlet, flood tidal delta, and tidal channel/creek facies. In addition to greater volumes, reservoirs composed of shoreface and foreshore facies have much better reservoir continuity and therefore can be developed with greater well spacing. Reservoirs composed of tidal inlet, flood tidal delta, and tidal channel/creek facies have much less continuity, which suggests that closer well spacing (or infill drilling in mature reservoirs) or horizontal wells will be most effective production strategies.

The ratio of maximum to minimum dimension for facies thickness, width, and length was compiled to determine the degree of variability of facies dimensions (Table 1). A ratio rather than standard deviation was used due to the fewer number of data. This data is from both modern and ancient shoreline barriers all over the world so it represents the maximum degree of variability. The variability of facies dimensions within reservoirs from the same play is expected to be much less. The greatest variability occurs in the thickness and width dimensions of the tidal inlet and tidal channel and creek facies. This is consistent with the depositional processes that formed the facies where the channeled flow deposits tend to migrate laterally and stack vertically during one cycle of deposition. A high degree of

MESOTIDAL BARRIER ISLAND FACIES DIMENSIONS

(Maximum dimensions reported in the literature)

Fig. 1 Dimensions and geometries of barrier island facies (after Jackson, 1992).² Data from references are listed in Table 1.

TABLE 1
Range of Dimensions of Major Facies in Recent and Ancient Mesotidal Shoreline Barrier Systems
Reported in the Literature.¹

Facies	Thickness, ft (Almond Outcrop)	Ratio of maximum to minimum thickness	Width, mi (Almond Outcrop)	Ratio of maximum to minimum width	Length, mi (Almond Outcrop)	Ratio of maximum to minimum length
Shoreface & Foreshore Facies	12.0 to 90.0 (48)	7.5	0.6 to 4.0 (1.4)	6.7	2.0 to 12.0 (6.4)	6
Washover Fan	0.5 to 6.0 —	12	0.4 to 1.6 —	4	0.8 to 1.8 —	2.3
Spit Platform	3.0 to 15.0 —	5	0.5 to 3.0 —	6	0.3 to 1.0+ —	3.3
Tidal Inlet	5.0 to 100.0+ (36)	20	0.1 to 1.0+ (0.6)	10	0.6 to 4.0+ (0.6)	6.7
Tidal Channel & Tidal Creek	5.0 to 100.0+ (44)	20	0.02 to 0.8 (0.3)	40	1.0 to 3.0+ (3.4)	3
Flood Tidal Delta	6.0 to 30.0 (35)	5	0.3 to 4.0 (1.6)	13.3	1.0 to 3.0 (2.4)	3
Ebb Tidal Delta & Shoal	15.0 to 75.0 (31)	5	1.0 to 10.0 (0.8)	10	1.5 to 6.0 (3.1)	4

¹Data compiled from Bernard et al., 1959; Cuevas et al., 1985; Donseelaar, 1984, 1990; Fitzgerald et al., 1984; Flores, 1978; Hayes and Sexton, 1989; Hoyt and Henry, 1965; Reinson, 1984; Roehler, 1979, 1988; Sha Li Ping, 1990; Snieder et al., 1984; Van Horn, 1979, and from NIPER's field observations (Szpakiewicz et al., 1986, 1990-91). The references are listed in reference 4 of this report, pp. 94-95.

Dimensions for the Almond Formation, Bar G (Roehler, 1988), Exposed in Outcrops on the East Flank of the Rock Springs Uplift are also indicated. The ratios of maximum to minimum values provide an indication of the degree of variability of the parameters.

variability also occurs in the width dimension of the flood and ebb tidal deltas. This may also be due to the fact that these facies are associated with tidal inlets that migrate laterally.

Major Depositional Characteristics of Studied Shoreline Barrier Reservoir Rocks

The Muddy formation in Bell Creek field and the Almond formation in Patrick Draw field produce from different shoreline barrier island facies. In Bell Creek field, stacking of several barrier-island microtidal depositional cycles was recognized.³ The shoreface facies compose most of producing intervals while the foreshore facies rank second. They were formed by marine processes of wave and tidal currents. The backbarrier facies play a subordinate role in Bell Creek and are represented by the washover, backshore, tidal channel, and tidal delta splay facies. Stacking of foreshore and shoreface sequences in the central part of productive Unit A resulted from small changes in relative sea level.

In the mesotidal shoreline barrier deposits of Patrick Draw field, mostly tide-dominated backbarrier facies formed by channeled flow from tidal currents are represented.⁴ Tidal inlet, tidal channel/creek, and flood tidal delta facies sequences compose most of the productive horizons.

The different depositional processes that formed the reservoir rocks in Bell Creek and Patrick Draw fields result in differences in facies dimensions, as shown in Fig. 1, which in turn control the compartment size within the reservoirs. Marine processes form relatively larger volume, laterally extensive units, while the channeled tide-dominated flow forms smaller units. The differences in reservoir continuity in Unit A of Bell Creek field and the Arch Unit in Patrick Draw field may be reflected in the recovery efficiency where total recovery (primary plus secondary) is 54% in Unit A of Bell Creek field and 48% in the Arch Unit of Patrick Draw field, even though Patrick Draw field produces from a much stronger gas cap expansion drive mechanism.

Differences in facies continuity between the Muddy and Almond formations are also clearly illustrated in outcrop cross-sections. Foreshore and shoreface facies, along with corresponding permeability profiles can be traced over distances of over 1.3 miles in outcrop exposures of the Muddy formation,⁵ whereas in outcrop exposures of the Almond formation, correlations of tidal channel and tidal delta facies are difficult over 1,200 ft.

The study of these two reservoirs illustrates the spectrum of characteristics found in shoreline barrier reservoirs. Because the two sandstones represent two end member conditions of the barrier island depositional system, it is unlikely that the information on reservoir characteristics could be transferable to another system intermediate between these two systems in so far as the mechanics of sediment deposition is concerned. It may be more appropriate to consider transferability of information to another system that was deposited under conditions similar to one of the two systems investigated.

Diagenetic Alterations in the Shoreline Barrier Reservoirs

Comparison of the two shoreline barrier types studied (microtidal and a mesotidal system) illustrates how different diagenetic histories result in different petrophysical characteristics regardless of sedimentological similarities. Early-stage leaching by (presumed) fresh water is present in both reservoirs. Subsequent diagenesis resulted in different flow characteristics. Although early leaching was very strong and important at Bell Creek, subsequent diagenesis only made minor modifications, slightly degrading the petrophysical properties of the barrier-related sandstones. In contrast, at Patrick Draw early-stage leaching was important (but not as strong as at Bell Creek) and subsequent diagenesis including compaction and cementation drastically reduced the petrophysical properties.

The list of diagenetic differences between the two fields is long and significant, particularly the presence of oysters at Patrick Draw and their total absence at Bell Creek. Such differences reflect the different intensity, paragenetic sequence, geochemistry, and thermal signature of the diagenetic fluids in the two different Rocky Mountain structural basins.

Petrographical analyses indicate that the original lithology of the sandstones in the two fields was different. That being the case, even the same sequence and intensity of diagenetic processes would result in different products, including petrophysical properties.

It would seem much more likely that the diagenesis of either of these fields would be more similar to other shoreline barrier reservoirs (or even unrelated depositional systems?) deposited from the same source (depocenter) which implies similar geological ages, undergoing the same or similar hydrographic processes, and ultimately (upon subsidence) similar diagenetic and thermal processes, similar structural styles, etc. if the fields to be compared were from the same play and at least within the same basin. The chances for transferring patterns of diagenesis, absolute values (such as porosity), or the significance of specific diagenetic stages would be much greater in such genetically similar fields than they would be across great distances and involving unrelated sedimentary accumulations in different basins.

Dominant Petrophysical Properties of Sandstones at Bell Creek and Patrick Draw Fields

From literature studies, the average porosity of 28.5% and 20% and arithmetic mean permeability of 2,250 mD and 40 mD encountered in Bell Creek and Patrick Draw fields, respectively are greater than the typical average porosity and permeability values commonly encountered in clastic oil reservoirs from other depositional environments. This probably explains why many nearshore reservoirs have been found to be above average producers of oil and gas in different basins around the world.

A strong inverse correlation (-0.82 and -0.84) between permeability and clay content and moderate correlation (0.70 and 0.65) between permeability and grain size are indicated from the correlation coefficients calculated between the various petrophysical parameters of sandstones from Bell Creek and Patrick Draw fields, respectively. The grain sizes were measured by point-counting from a thin section and the permeabilities obtained from measurements on core plugs at the same depth. The lack of a stronger direct correlation between grain size and permeability could be attributed to the fact that grain size varies significantly within a short vertical distance, whereas the permeability values are the averages within the dimension of the core plug. This is illustrated by the plots of the permeability versus the grain size and V_{cl} for well W-7 (Fig. 2) from Bell Creek field and well Arch 120 (Fig. 3) from Patrick Draw field. It may be noted from the two figures that the maximum grain size and permeability in well W-7 and well Arch 120 are 240 microns and 1,100 mD and 180 microns and 45 mD, respectively. There is moderate correlation of grain size with porosity in both the fields (correlation coefficient around 0.5 to 0.6). Sorting of the grain size which is obtained from the standard deviation of the grain size distributions, has a much stronger correlation with porosity.

Besides the detrital clays, strong control on permeability is exerted also by the diagenetic clays and carbonate cements. Significant responses of the sonic and the density logs have been documented in the cemented intervals.

It is unlikely that the information on petrophysical properties could be transferable from the two shoreline barrier reservoirs to another system intermediate between these two end member systems in so far as the mechanics of sediment deposition is concerned. It may be more appropriate to consider transferability of information to another system that was deposited under conditions similar to one of the two systems investigated.

Fig. 2 Effect of grain size and V_{cl} on permeability in sandstone from Well W-7, Bell Creek field, Montana.

Fig. 3 Effect of grain size and V_{cl} on permeability in sandstone from Arch 120 well, Patrick Draw field, Wyoming.

Structural Features of the Two Studied Shoreline Barrier Systems

The structural contours at the top of the best productive shoreline barrier sandstones in Bell Creek field and at the top of the UA-5B sandstones of the same origin in Patrick Draw field reveal the following dominant structural features of the two reservoirs: (1) the hydrocarbon traps in both the fields are essentially stratigraphic in nature in which hydrocarbons are trapped by low permeability nearshore sediments at the updip end of the structure, and (2) detailed mapping with wireline logs at Bell Creek field and with log and seismic data at Patrick Draw field indicate the presence of several small faults (throw around 30 ft or less) in both the fields. At least some of the faults act as semi-permeable barrier to fluid movement in both reservoirs. This effect is most noticeable in the carbonate cemented sandstones from the northern parts of the Arch Unit at Patrick Draw field. Faults with very large throws have not been mapped. Faulting and fracturing of reservoir sandstones in the Powder River Basin and Greater Green River Basin are more related to the regional tectonic and compaction scenarios than to the environment of their deposition. Therefore, transferability of structural features between shoreline barrier reservoirs located in different sedimentary basins is questionable until similar tectonic style is proven by geologists.

Geochemical Features & Anomalies

Geochemical analyses of pre-waterflood oil associated reservoir waters from the Almond formation of Patrick Draw field clearly demonstrate heterogeneous characteristics and anomalous distribution.⁶⁻⁷ Hydrogeochemical heterogeneity of the original oil associated formation waters in Patrick Draw field is in strong contrast with a perplexing homogeneity of pre-waterflood formation waters in Bell Creek field.

The contrasting geochemical features in both studied shoreline barrier reservoirs, as well as the other examples

known from literature, indicate that their present geochemical environments had little or no relation to the depositional environment of shoreline barrier sediments. Instead, they clearly resemble the regional hydrodynamic systems. However, early mixing of coastal meteoric waters with saline marine water is unique for the barrier island systems. The early geochemical alterations in yet unconsolidated sediments can be specifically attributed to the shoreline barrier systems where hydrodynamic balance between the coastal fresh meteoric water lenses and surrounding marine/lagoonal waters is constantly maintained due to the differences in water densities. Modern analogs can provide information on the products of the early water-sediment interaction processes.

Reservoir Hydrodynamics

Approximate boundaries of mega-compartments several square miles in area have been inferred in Patrick Draw field on the basis of the mapped contrasts in formation water salinities, documented heterogeneity of hydrochemical facies, and monitored changes of bottomhole pressures. The reservoir partitioning may impose serious restrictions on fluid movement. The presence of an extensive gas cap and highly saline and higher density formation waters in the updip portion of the reservoir strongly indicates that direct hydraulic communication between the Almond formation outcrops and the hydrocarbon productive backbarrier sandstones in deeper parts of the Washakie Basin has been interrupted.

Hydrodynamic drive in Bell Creek field toward depths of the Powder River Basin adds 429 ft (86 % of total oil column) to the 68 ft of calculated hydrostatic oil column. Downdip flow of water through the selectively leaking barriers also explains lack of extensive gas caps in the reservoir. Geochemical and hydrodynamic data indicate leakage of some fluids through lagoonal deposits which form the stratigraphic trap to liquid hydrocarbons. In contrary to Patrick Draw field, the hydraulic system in Bell Creek field seems to be open to the surface. This indicates that the natural hydrodynamics of the two studied shoreline barrier reservoirs is field or basin specific and therefore, the information on dynamic fluid flow pattern cannot be directly transferred within the genetic group of reservoir sediments except for the reservoirs which are located within the same hydrodynamic system. In the case of flowing systems like in Bell Creek field, the hydrodynamic drive governs the original distribution of hydrocarbons and their quantity. In the open flowing systems also the quality of hydrocarbons is affected by unequilibrated fluid-fluid and rock-fluid interaction processes. During reservoir development the role of natural hydrodynamic flow decreases within the oil column giving way to the imposed short-term flow conditions caused by production and /or injection processes which override the larger scale natural hydrodynamic drive. Oil, however, was distributed within the reservoir rock system under the long-term natural hydrodynamic conditions. Therefore, reconstruction of pre-development conditions, coupled with detailed reservoir

characterization, provides a chance for predicting the location and quantity of remaining oil.

Summarized Comparison of Bell Creek and Patrick Draw Reservoir Geology with the Emphasis on Transferability Potential

The general type, geometry, arrangement, and volumetrics of depositional facies may be considered unique for the ancient shoreline barrier deposits, and therefore they can be transferable with certain restrictions from one reservoir to another. The restrictions in transferability result mostly from differences in facies types and different arrangements of dominant facies deposited under the microtidal or mesotidal coastal hydrodynamic regimes of the same general environment of deposition.

Although the productive sandstones in Patrick Draw and Bell Creek fields are of shoreline barrier origin and both are good producers of hydrocarbons, the two sandstones have widely different ranges of porosity, permeability, grain size, and distribution of oil saturations since they represent the end member systems that were deposited under significantly different coastal hydrodynamic regimes. Because the two sandstones represent two end member conditions, it is unlikely that the information on reservoir characteristics could be transferable to another system intermediate between these two systems in as far as the mechanics of sediment deposition is concerned. It may be more appropriate to consider transferability of information to another system that was deposited under conditions similar to one of the two systems investigated.

Petrographical analyses strongly indicate that the original lithology of shoreline barrier sandstones differed depending on the source of clastic material subsequently reworked by wave and tidal processes. That being the case, even the same sequence and intensity of diagenetic processes would result in different products, including petrophysical properties.

Post-depositional history of the preserved shoreline barrier deposits imposes more restrictions on transferability of data from one reservoir to another. There are some indications that the reservoir information such as petrophysical, diagenetic, geochemical, hydrodynamic, and structural can be more successfully transferred within the same basin where sediments were exposed to the comparable post-depositional processes such as depth of burial, temperature, pressure, tectonic stresses, and chemistry of migrating fluids under similar region-specific hydrodynamic conditions.

Our study of the two shoreline barrier reservoir systems and the relevant outcrop exposures of the producing formation provided guidance for improved characterization of this type of hydrocarbon-bearing reservoirs. The study revealed the importance of the postdepositional geologic alterations caused by thermal and pressure history, and changing geochemistry of the system under different subsurface hydrodynamic conditions. These factors finally shaped the reservoir properties and strongly affected the imposed fluid flow pattern during reservoir development.

The geochemical history is rarely reconstructed for a comprehensive reservoir characterization.

Both reservoirs studied are of Cretaceous age, occur at similar depth, and are located in the Rocky Mountain geologic province. Paleohistory of the Powder River and Greater Green River basins, however, was significantly different. The post-depositional processes which shaped the storage and flow capacity of reservoirs within the two basins were also different. Therefore, the characteristics and performance of the two reservoirs differ significantly despite their genetic similarities.

It is expected that the overall depositional architecture of the shoreline barrier reservoirs could be successfully transferred from one reservoir to another provided that the depositional processes are well defined by geologists and that the same location within the sedimentary subsystem is established. Although much more data must be collected and analyzed to quantify the variability of facies dimensions and the error bars associated with transferring facies dimensions from one reservoir to another, our preliminary analysis suggests that dimension data from shoreface, foreshore, washover, and spit platform facies, as well as thickness and length of tidal deltas may be less variable and therefore more easily transferred from one reservoir to another than those from tidal inlet, tidal channel, tidal creek facies and tidal delta width. Reservoir petrophysical, structural, geochemical, and hydrodynamic characteristics, however, are field-or-basin-specific and need

to be superimposed on the depositional characteristics inferred by analogy.

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TORIS RESEARCH SUPPORT

Cooperative Agreement DE-FC22-83FE60149,
Project BE2

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Oct. 1, 1983
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Funding for FY 1993: \$340,000

Principal Investigator:
James F. Pautz

Project Manager:
Chandra M. Nautiyal
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objective

The objective of this project is to provide research support to the DOE Program Manager for the Tertiary Oil Recovery Information System (TORIS) in the areas of enhanced oil recovery (EOR) projects and reservoir data

base management, EOR project technology and trends analysis, and computer simulation.

Summary of Technical Progress

The Department of Energy encouraged oil companies and operators to undertake enhanced oil recovery (EOR) projects through the tertiary incentive program (TIP) from 1979 to 1980. Those companies and operators that received an incentive have been asked to submit annual reports. Initially, the companies were required to certify the projects as true EOR operations. A total of 423 certifications were received. After the requirements for the Annual Reports for Enhanced Oil Recovery Incentive Projects were published, any response was voluntary. Each year after 1982, operators have been requested to return a completed "Annual Report for Enhanced Oil Recovery Incentive Program," form FE-748. The information from these annual reports is used to maintain the Enhanced Oil Recovery Project Data Base used by the Bartlesville Project Office (BPO). Maintaining this data base is part of this project.

Since 1986, NIPER has surveyed the operators for annual information. Unfortunately, the number of completed reports is decreasing because many of the original projects have been terminated, completed, changed, were never started, or are not reporting. For the 1986 reporting year, information was obtained on 150 projects of

which 110 projects were active. As of the last report,¹ only 52 projects were reported as active. Since the report, another three projects reported for a total of 55 active, reporting TIP projects for 1990. Estimated incremental oil recovery was 29.3 million bbl in 1990 or roughly 10% of the domestic EOR production.

FE-748 forms were sent to operators of EOR projects in March 1992 requesting information for calendar years 1991 and previous years. A followup telephone survey was made in January 1993, and a mail request was made in February 1993 to those operators that had not responded for 1991 information.

A total of 55 FE-748 forms and one refusal were received for 1991. Of this information, 41 projects were active, 10 were terminated, two had been deferred, one was completed, and one was active but refused to respond. This compared to 56 active projects reporting for 1990. Table 1 displays

selected data on each of the 1991 projects. These 41 projects reported 31.0 million barrels of incremental oil or over 10% of the total estimated enhanced oil recovered during 1991 and 6% more than was reported by TIP projects in 1990.

In addition, information on four projects was received for 1990 since the previous report. One of these projects (SF204) is a project purchased by Crete Oil Company during 1990 from Marathon – both operators reported their production for the portion of the year each owned the operation. Table 2 contains selected information about these projects.

Reference

1. C. A. Sellers, J. F. Pautz, and B. Fox, *Addition of 1990 Data for Tertiary Incentive Projects and Other Data to the DOE EOR Project Data Base*, DOE Report NIPER-626, September 1992.

TABLE 1
Summary of the FE-748s Submitted for 1991

Project no.	Year	Project status	Process type	Incremental oil production ¹	Operator
SF011	1991	Active	Miscible Gas Displacement	61	Pennzoil Exp. & Prod. Co.
SF018	1991	Active	Steam	1,458	Union Oil Co. of CA
SF037	1991	Active	Polymer Augmented Waterflooding	84	Phillips Petroleum Co.
SF041	1991	Active	Miscible Gas Displacement	2,431	Chevron U.S.A. Inc.
SF085-87	1991	Shut In	Miscible Gas Displacement	87	Citronelle
SF092	1991	Completed	Steam		Chevron U.S.A. Inc.
SF094	1991	Deferred	Steam		Chevron U.S.A. Inc.
SF096H	1991	Active	Steam	400	Chevron U.S.A. Inc.
SF097	1991	Active	Steam	990	Chevron U.S.A. Inc.
SF098H	1991	Active	Steam	820	Chevron U.S.A. Inc.
SF101	1991	Terminated	Steam		Chevron U.S.A. Inc.
SF107	1991	Active	Steam	52	Chevron U.S.A. Inc.
SF108	1991	Active	Steam	964	Chevron U.S.A. Inc.
SF110	1991	Active	Steam	398	Chevron U.S.A. Inc.
SF111	1991	Active	Steam	683	Chevron U.S.A. Inc.
SF120	1991	Terminated	Steam	192	Chevron U.S.A. Inc.
SF121	1991	Active	Steam	107	Chevron U.S.A. Inc.
SF122H	1991	Active	Steam	611	Chevron U.S.A. Inc.
SF123	1991	Active	Steam	1,479	Chevron U.S.A. Inc.
SF124	1991	Active	Steam	1,057	Chevron U.S.A. Inc.
SF125	1991	Active	Steam	1,720	Chevron U.S.A. Inc.
SF127	1991	Active	Steam		Chevron U.S.A. Inc.
SF131	1991	Active	Miscible Gas Displacement	604	Phillips Petroleum Co.
SF135	1991	Active	Miscible Gas Displacement	615	Conoco
SF149	1991	Terminated	Steam	8	Thums

¹Mbbl

TABLE 1
Summary of the FE-748s Submitted for 1991 (continued)

Project no.	Year	Project status	Process type	Incremental oil production ¹	Operator
SF167	1991	Active	Miscible Gas Displacement	1,776	Arco Oil and Gas Co.
SF168	1991	Active	Miscible Gas Displacement	322	George R. Brown
SF169	1991	Active	Miscible Gas Displacement	169	Phillips Petroleum Co.
SF171	1991	Active	Miscible Gas Displacement	1,713	Hunt Oil
SF178	1991	Active	Alkaline Flooding		Conoco
SF204	1991	Active	Microemulsion Flooding	75	Crete Oil Company
SF206	1991	Active	Polymer Augmented Waterflooding		Meridian Oil, Inc
SF219	1991	Active	Miscible Gas Displacement		Amerada Hess
SF222	1991	Active	Miscible Gas Displacement	225	ENRON
SF228	1991	Active	Steam		Union Oil Co. of CA
SF241	1991	Terminated	Steam	169	Chevron U.S.A. Inc.
SF242	1991	Terminated	Steam	77	Chevron U.S.A. Inc.
SF243	1991	Terminated	Steam	24	Chevron U.S.A. Inc.
SF245	1991	Active	Steam	141	Chevron U.S.A. Inc.
SF247	1991	Active	Steam	1,067	Chevron U.S.A. Inc.
SF249	1991	Deferred	Steam		Chevron U.S.A. Inc.
SF251	1991	Terminated	Steam	4	Chevron U.S.A. Inc.
SF252	1991	Terminated	Alkaline Flooding	30	Chevron U.S.A. Inc.
SF305	1991	Active	Miscible Gas Displacement	1,063	Arco Oil and Gas Co.
SF309	1991	Active	Miscible Gas Displacement	500	Arco Oil and Gas Co.
SF341	1991	Active	Steam		Arco Oil and Gas Co.
SF343	1991	Active	Steam		Arco Oil and Gas Co.
SF345	1991	Active	Steam	2,532	Atco Oil and Gas Co.
SF346	1991	Active	Steam		Union Oil Co. of CA
SF370H	1991	Active	Steam	3,272	Chevron U.S.A. Inc.
SF380	1991	Terminated	Miscible Gas Displacement		Mobil E & P Inc.
SF381	1991	Terminated	Miscible Gas Displacement		Mobil E & P Inc.
SF382	1991	Active	Miscible Gas Displacement		Mobil E & P Inc.
SF383	1991	Active	Miscible Gas Displacement		Mobil E & P Inc.
SF422	1991	Active	Steam	3,008	Chevron U.S.A. Inc.
Total incremental production				30,986	

¹ Mbbl

TABLE 2
Summary of the FE-748s Submitted for 1990 Since the Last Status Report

Project no.	Year	Project status	Process type	Incremental oil production ¹	Operator
SF167	1990	Active	Miscible Gas Displacement	1,987	Arco Oil and Gas Co.
SF204	1990	Active	Microemulsion Flooding	24	Crete Oil Company
SF309	1990	Active	Miscible Gas Displacement	478	Arco Oil and Gas Co.
SF346	1990	Active	Steam		Unocal
Total incremental production				2,489	

¹ Mbbl

UPGRADE THE BPO CRUDE OIL ANALYSIS DATA BASE

Cooperative Agreement DE-FC22-83FE60149, Project SGP56

**National Institute for Petroleum and Energy Research
Bartlesville, Okla.**

**Contract Date: June 1, 1993
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$192,000**

**Principal Investigators:
James F. Pautz
Johanna Shay**

**Project Manager:
Chandra M. Nautiyal
Bartlesville Project Office**

Reporting Period: April 1 - June 30, 1993

Objective

The purpose of this work is (1) to develop and maintain a crude oil analysis (COA) data base on-line and available to the public that maintains data integrity and system security, (2) to upgrade and update crude oil analyses for inclusion in this database, and (3) to participate in the UNITAR analysis study group.

Summary of Technical Progress

Repetitive requests are made by users of the Crude Oil Analysis Data Base for information in addition to what they can currently obtain from the data base. The requests

are for information such as well location and number, type of producing zone, source of sample (wellhead, separator, tank, etc.), metal content, hydrocarbon types, benzene, ethyl-benzene, toluene, and xylene (BETX) content.

Metal Content

Metal analyses for 18 heavy crude oils (API gravity < 20) using an inductively coupled plasma atomic emission spectrometer (ICP-AES) were finished. A portion of a homogenized crude oil was weighed and then diluted with tetralin on a weight-by-weight basis. Standards were prepared in the same manner. An internal standard (Sc) was added to the solutions to compensate for variations in sample-solution introduction efficiency. The solutions were introduced by using a peristaltic pump to an ICP-AES. By comparing emission intensities of elements in the crude sample with emission intensities measured with the standards, the concentrations of elements in each crude sample were calculated.¹

Metal contents for these 18 crude oils are shown in Table 1.

Vanadium and nickel have been studied more thoroughly than any other metallic elements found in petroleum. The reason is that both of these elements occur in part as nitrogen complexes (porphyrins) closely related to chlorophyll and hemoglobin and thus appear to be associated with the genesis of crude oil. Many correlations based on V and Ni content have been made in attempts to obtain information on the geological and geographical origins of petroleum.²

The iron and copper contents as well as those of the less prominent elements are apt to vary in more erratic ways in contrast with the regularity observed in nickel and vanadium. This may be due to contamination from sources other than petroleum itself; for instance, rocks, brine, or well equipment. The presence of brine salts ions Na, Mg, K, and Ca in these 18 heavy crude oils is evidence of undesirable contamination by salt water.

Hydrocarbon Types up to C13 (455° F) and BETX

A knowledge of the hydrocarbon components comprising a petroleum naphtha is useful in valuation of crude oils, in product quality assessment, and for regulatory purposes. Detailed hydrocarbon composition is also used as input in the mathematical modeling of refinery processes.

Determination of paraffins, isoparaffins, aromatics, and naphthenes (PIAN) up to C13 as well as BETX content for 14 heavy crude oils using gas chromatography were completed. A representative portion of the crude with an internal standard (isooctane) was introduced into a gas chromatograph equipped with a methyl silicone bonded phase, fused silica capillary column. The vaporized sample was transported by helium carrier gas through the column in which the components are separated. Components were detected by a flame ionization detector as they eluted from the column. The detector signal was processed by an integrating computer. Each eluting peak was identified by comparing its retention index to a table of retention indices and by visual matching with a standard chromatogram. The concentration of each component was calculated by the following equations:

$$W_c = \frac{A_c \times R_{Fc} \times W_{is}}{A_{is} \times R_{Fis}}$$

where:

Ac = area of peak representing component c
Ais = area of internal standard (i-C8) peak
R_{Fc} = response factor of component c
R_{Fis} = response factor of internal standard (i-C8)
W_{is} = weight of internal standard (i-C8)
W_c = weight of component c

$$\text{Volume \% of component c} = \frac{W_c \times SG_s}{SG_c \times W_s} \times 100\%$$

where:

W_c = weight of component c
W_s = weight of sample (crude oil)
SG_c = specific gravity of component c
SG_s = specific gravity of sample

Hydrocarbon types (PIAN) up to C13 and BETX data for these 14 heavy crude oils are very low as listed in Table 2.

References

1. M. Gonzales and A. W. Lynch, Methods Development for Trace Metal Characterization of Crude Oil by Inductively Coupled Plasma Atomic Emission Spectroscopy. *Modern Instrumental Methods of Elemental Analysis of Petroleum Products and Lubricants*. ASTM STP 1109, 1991, pp.62-69.
2. V. Valkovic, *Trace Elements in Petroleum*. The Petroleum Publishing Company, Tulsa, Okla., 1978.

TABLE 1

Metal Content for Analyzed Crudes

Field	State	Sample number	°API	P ppm	V ppm	Zn ppm	Cu ppm	Ni ppm	Fe ppm
Wesson	Ark	65028	18.6	.424	3.12	.341	.192	4.93	2.44
Artesian	Ark	65032	12.7	1.28	9.50	7.26	.785	23.0	.958
Hampton	Ark	65033	15.0	1.34	11.8	1.39	.910	23.1	3.60
Champagnolle	Ark	65035	15.9	.335	6.36	.268	.109	6.44	1.09
Gum Creek	Ark	65036	16.4	.498	4.00	.563	.072	4.43	6.57
Troy,N	Ark	65041	22.5	.350	2.67	.113	.057	6.23	.860
Wilmington	Cal	66094	18.9	.960	46.9	.820	.207	68.5	40.5
Wilmington	Cal	66095	15.9	1.22	56.5	.810	.136	75.0	37.1
Wilmington	Cal	66096	18.9	1.07	43.9	.698	.174	70.3	48.5
Toxey	Al	69112	19.4	1.20	5.43	.176	.062	12.4	.192
Cat Canyon,W	Cal	70042	14.2	5.95	298	.794	.240	143	1.49
Toxey	Al	70088	17.0	1.20	6.02	.202	.532	14.3	.288
New London,N	Ark	71034	11.1	.898	13.1	.756	.032	27.4	.752
Minden	La	72039	17.4	.548	17.2	.106	<.001	9.52	.348
Minden	La	72040	17.0	.762	18.2	.446	.155	10.3	.180
Ada	La	73006	20.2	.600	14.3	.518	<.001	8.75	.928
Hasley Canyon	Cal	77023	11.1	3.03	591	1.12	.100	176	22.9
Wilmington	Cal	77034	17.6	2.26	81.7	.907	.012	76.3	38.6

TABLE 2
Hydrocarbon Types (PIAN) up to C13 and BTX Data for Analyzed Crudes

Field	State	Sp. #	°API	Paraffins vol. %	i-Paraffins vol. %	Aromatics vol. %	Ethyl-Benzene vol. %	Naphthenes vol. %	Benzene vol. %	Toluene vol. %	Xylenes vol. %
Whittier	Cal	76066	22.1	0.856	5.400	2.393	0.199	4.855	0.003	0.013	0.116
Bayou Middle Fork	La	72049	18.6	2.749	3.906	0.886	0.014	1.213	0.034	<0.002	0.065
Gum Creek	Ark	70116	21.6	6.519	6.657	3.009	0.137	2.366	0.079	0.272	0.349
Toxey	Al	69112	19.4	6.260	6.343	2.895	0.159	2.045	0.066	0.231	0.236
Wilmington	Cal	77034	17.6	0.907	3.546	1.769	3.388	0.073	0.005	0.014	0.106
Minden	La	72039	17.4	2.817	6.411	1.748	0.016	1.960	0.148	0.079	0.207
Ada	La	73006	20.2	3.424	5.957	1.383	0.008	2.042	0.017	0.003	0.131
New London, North	Ark	71034	11.1	1.589	2.916	1.578	0.051	1.351	0.030	0.076	0.103
Minden	La	72040	17.0	2.019	4.693	1.140	0.013	1.571	0.132	0.041	0.164
Toxey	Al	70088	17.0	7.010	7.229	3.073	0.188	2.393	0.094	0.296	0.285
GumCreek	Ark	70116	21.6	5.964	5.813	2.813	0.143	2.108	0.061	0.196	0.253
Wilmington	Cal	66096	18.9	1.120	4.263	1.306	0.121	4.921	<0.002	0.002	0.125
Wilmington	Cal	66095	15.9	0.709	2.890	0.853	0.085	2.776	<0.002	0.002	0.054
Wilmington	Cal	66094	18.9	1.589	4.887	1.596	0.124	5.058	<0.002	0.026	0.137

**COMPILATION AND ANALYSIS OF OUTCROP
DATA FROM THE MUDDY AND ALMOND
FORMATIONS**

Cooperative Agreement DE-FC22-83FE60149,
Project SGP69

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Sept. 21, 1992
Anticipated Completion: May 31, 1993
Funding for FY 1993: \$24,000

Principal Investigator:
Susan Jackson

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this project are to compile outcrop data from the Muddy and Almond formations, supply missing data, perform interpretations and analyses where needed, and process data for a transferable format so that it can be used by those interested.

Summary of Technical Progress

A fractured reservoir model was constructed based on data collected from the outcrop.

The shape factor obtained from the analytical method was incorporated into a dual-porosity reservoir simulator. Numerical simulation of fluid flow from a single fractured rock block is being conducted for comparison with results from the analytical solution.

**HORIZONTAL WELL PRODUCTION
FROM FRACTURED RESERVOIR**

Cooperative Agreement DE-FC22-83FE60149,
Project SGP73

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract date: Feb. 1, 1993
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$40,000

Principal Investigator:
Ming-Ming Chang

Project Manager:
Tom Reid
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objectives

The objective of this project is to determine effects of natural fractures on horizontal well production using numerical simulation to provide guidelines, screening criteria, or analytical predictions of horizontal well production.

Summary Of Technical Progress

To investigate fluid flow from fractured rock matrix the diffusivity equation was solved under the unsteady state production condition. This analytical solution is then taken to derive the shape factor to be used in the dual-porosity or dual-permeability numerical reservoir simulator.

The shape factor in the transfer function was derived by solving the three-dimensional diffusivity equation of a rock matrix block under unsteady state production, in contrast to the pseudo-steady state condition assumed by most previous studies denoted in the literature. The diffusivity equation in the x, y, and z coordinate was solved in two cases by assuming different boundary conditions of (1) constant fracture pressure and (2) constant flow rate.

Shape factor values are high at the initial depletion stage under the unsteady state condition. When the fracture pressure is constant, the shape factor converges to π^2/L^2 , $2\pi^2/L^2$ and $3\pi^2/L^2$ for one-, two-, and three-dimensional rock matrix, respectively, at the dimensionless time (t_D) of about 0.1. The 'L' value in the shape factor formula is the length of rock matrix. The period of 0.1 for t_D ranges from less than 1 day for commonly encountered fractured reservoirs to months for large and tight fractured rock.

When the flow rate between the rock matrix and the fracture is constant, the fracture pressure varies with location on the rock surface. Based on the average fracture

pressure, the shape factor decreases with production time until a t_D value of 0.1 is reached. The shape factor values converging at 0.1 are $12/L^2$, $24/L^2$, and $36/L^2$, for one-, two-, and three-dimensional rock matrix flow, respectively. The shape factors calculated from the case of constant flow rate are 1.2 times of those from the case of constant fracture pressure.

The shape factor values calculated from unsteady state production are higher than those proposed by Kazemi¹ and by Coats², but less than those by Warren and Root³.

Background

Many fractured reservoirs are characterized by an interconnected fractured network dividing the matrix rock into a multitude of separate blocks. Flow between the matrix block and the fracture is accounted for by a shape factor in a transfer function. This transfer function is virtually Darcy's law expressed over some mean path between the matrix block and the adjacent fracture:

$$q = \frac{kV}{m} r (p_f - \bar{p}_m) \quad (1)$$

where σ , the shape factor, can be rewritten as

$$\sigma = \frac{q\mu}{kV(p_f - \bar{p}_m)} \quad (2)$$

Equation 1 depends on a discrete gradient given by the distance between the pressure at the fracture and the block's average internal pressure, and acts through a certain depth ΔL into the block. Comparing Eq. 1 to the transfer flow in the Darcy flow format:

$$q = \frac{kA}{\mu} \frac{(p_f - \bar{p}_m)}{\Delta L} \quad (3)$$

we obtain $\sigma = A / (V\Delta L)$ (4)

or $\Delta L = A / (V\sigma)$ (5)

Warren and Root³ proposed an expression for the shape factor as

$$\sigma = 4N(N+2)/L^2 \quad (6)$$

where L is the length of the matrix block and N is the number of normal sets of fractures: 1, 2, or 3. If rock blocks have dimensions: a , b , and c , then

$$\begin{aligned} L &= a \text{ for } N = 1 \\ L &= 2ab/(a+b) \text{ for } N = 2 \\ L &= 3abc/(ab+bc+ca) \text{ for } N = 3 \end{aligned} \quad (7)$$

The basis of this expression is not known.

An accurate value of shape factor is needed to properly account for the fluid flow between the fracture and the rock matrix in model calculations.

Mathematical Model

Since many fractured reservoirs are characterized by a multitude of separate blocks divided by an interconnected fractured network, the model investigated in this study is a parallelepiped rock matrix. The unsteady flow of a slightly compressible single-phase fluid of constant viscosity is considered in an anisotropic rock matrix. The pressure distribution is analyzed for one-, two-, and three-dimensional flow in the x , y , and z Cartesian coordinate from the rock matrix to the fracture. The diffusivity equation solved for the flow is:

$$k_x \frac{\partial^2 p}{\partial x^2} + k_y \frac{\partial^2 p}{\partial y^2} + k_z \frac{\partial^2 p}{\partial z^2} = \phi \mu c_i \frac{\partial p}{\partial t} \quad (8)$$

The initial pressure is assumed uniform throughout the rock matrix, or

$$p = p_i \text{ when } t = 0 \quad (9)$$

The pressure and fluid flow of the rock matrix was solved for two cases by assuming different boundary conditions of (1) constant fracture pressure and (2) constant flow rate. For the case of constant fracture pressure,

$$p = p_f \text{ when } x = 0 \text{ or } a; \text{ or } y = 0 \text{ or } b; \text{ or } z = 0 \text{ or } c \quad (10)$$

For the case of constant flow rate,

$$\frac{\partial p}{\partial x} = C \text{ when } y = 0 \text{ or } b \quad (11)$$

Similar boundary conditions apply to x and z directions for 2- and 3- dimensional flow. In this analysis, the following dimensionless terms are introduced.

$$\begin{aligned} \text{dimensionless distance: } x_D &= \frac{x}{a}, y_D = \frac{y}{b}, \text{ and} \\ z_D &= \frac{z}{c} \end{aligned} \quad (12)$$

$$\text{dimensionless pressure: } p_D = \frac{p_i - p}{p_i - p_f} \quad (13)$$

$$\text{dimensionless time: } \tau = \frac{k_x t}{a^2 \phi \mu c_i} \quad (14)$$

Thus, Eqs. 8 to 11 can be converted, respectively, into:

$$\begin{aligned} \frac{\partial^2 p_D}{\partial x_D^2} + K_y \frac{\partial^2 p_D}{\partial y_D^2} + K_z \frac{\partial^2 p_D}{\partial z_D^2} &= \frac{\partial p_D}{\partial \tau} \quad (8a) \\ \text{where } K_y &= \frac{a^2 k_y}{b^2 k_x}, \text{ and } K_z = \frac{a^2 k_z}{b^2 k_x} \end{aligned}$$

$$\text{initial condition: } [P_D]_{t=0} = 0 \quad (9a)$$

$$\text{boundary condition for constant fracture pressure case:} \\ [p_D]_{x_D=0,1} = 1 \quad (10a)$$

$$[p_D]_{y_D=0,1} = 1 \quad (10b)$$

$$[p_D]_{z_D=0,1} = 1 \quad (10c)$$

boundary condition for constant flow rate case:

$$\left[\frac{\partial p_{Dy}}{\partial y_D} \right]_{y_D=1} = u_1 \quad (11a)$$

$$\left[\frac{\partial p_{Dy}}{\partial y_D} \right]_{y_D=0} = u_1 \quad (11b)$$

Similar boundary conditions to 11a, 11b can be assigned to x and z directions for the rock matrix having two or three normal sets of fractures.

Constant Fracture Pressure Solutions

Using the method of separation of variables, p_D in Eq. 8a was solved subject to conditions 9a and 10a for three-dimensional fluid flow as

$$p_D = \frac{64}{\pi^3} \sum_{l=0}^{\infty} \sum_{m=0}^{\infty} \sum_{n=0}^{\infty} \frac{\exp(-Ft)}{(2l+1)(2m+1)(2n+1)} \sin(2m+1)\frac{\pi x}{a} \cdot \sin(2n+1)\frac{\pi y}{b} \cdot \sin(2l+1)\frac{\pi z}{c} \quad (15)$$

where

$$F = [(2m+1)^2 \frac{k_x}{a^2} + (2n+1)^2 \frac{k_y}{b^2} + (2l+1)^2 \frac{k_z}{c^2}] \frac{\pi^2}{\phi \mu c_t} \quad (16)$$

The corresponding flow rate at $x = a$ is:

$$q_{x=a} = 256 (p_m - p_f) \frac{k_x b c}{\mu a \pi^4} \sum_{l=0}^{\infty} \sum_{m=0}^{\infty} \sum_{n=0}^{\infty} \frac{1}{(2l+1)^2 (2n+1)^2} \exp(-Ft) \quad (17)$$

The average pressure in the rock matrix can be obtained from integration of p_D in formula 15:

$$\bar{p}_D = 1 - \frac{512}{\pi^6} \sum_{l=0}^{\infty} \sum_{m=0}^{\infty} \sum_{n=0}^{\infty} \frac{\exp(-Ft)}{(2l+1)^2 (2m+1)^2 (2n+1)^2} \quad (18)$$

and the shape factor can be calculated following formula 2 as

$$\sigma = \frac{A}{B} \quad (19)$$

where

$$A = \pi^2 \sum_{l=0}^{\infty} \sum_{m=0}^{\infty} \sum_{n=0}^{\infty} \frac{\exp(-Ft)}{(2l+1)^2 (2m+1)^2 (2n+1)^2} \left[\frac{(2m+1)^2}{a^2} + \frac{(2n+1)^2}{b^2} + \frac{(2l+1)^2}{c^2} \right] \quad (20)$$

$$B = \sum_{l=0}^{\infty} \sum_{m=0}^{\infty} \sum_{n=0}^{\infty} \frac{1}{(2l+1)^2 (2m+1)^2 (2n+1)^2} \exp(-Ft) \quad (21)$$

For the one-dimensional matrix-fracture flow in the x-direction, the shape factor is

$$\sigma_{1D} = \frac{\pi^2}{a^2} \frac{\sum_{m=0}^{\infty} \exp[-(2m+1)^2 \pi^2 \tau]}{\sum_{m=0}^{\infty} \frac{1}{(2m+1)^2} \exp[-(2m+1)^2 \pi^2 \tau]} \quad (22)$$

The shape factor as shown in formulas 19-22 is time-dependent under the unsteady flow condition. As flow time proceeds, the shape factor value for 1-D flow in formula 19 converges to π^2/a^2 during QSS. This convergence can be seen by the sharp decline of values for the second ($m=1$) and following ($m>1$) terms in comparison to the first term ($m=0$) for both numerator and denominator series as τ value increases. Thus, the numerator and denominator series in 22 are canceled out at large time values. For the same reason the shape factor for 3-D fractured rock flow converges to $\pi^2(1/a^2 + 1/b^2 + 1/c^2)$ with time.

Constant Flow Rate Solutions

Pressure and flow within the rock matrix produced at a constant flow rate to the fracture was solved from the diffusivity equation in one-dimensional case first. The solution to the 2- and 3-dimensional diffusivity equation 8 can be derived from the 1-D solution based on the principle of superposition.

The 1-D diffusivity equation in the y-axis is given as

$$\frac{a^2 k_y}{b^2 k_x} \frac{\partial^2 p_{Dy}}{\partial y_D^2} = \frac{\partial p_{Dy}}{\partial \tau} \quad (23)$$

Equation 23 can be solved in two steps. In the first step, an additional boundary condition of formula 24a was assumed in addition to the initial condition 9a and boundary condition 11a. Formula 24a assumes no flow to the fracture at $y_D = 0$. No-flow conditions were also assumed at $X_D=0$, $X_D=1$, $Z_D=0$, and $Z_D=1$. Rock flow is only allowed at $y_D = 1$ at a constant rate u_1 (formula 11a).

$$\left[\frac{\partial p_{Dy}}{\partial y_D} \right]_{y_D=0} = 0 \quad (24a)$$

Using Laplace transform, the dimensionless pressure was solved from Eq. 23 as:

$$p_{Dy} = u_1 \sum_{n=0}^{\infty} \left[2\sqrt{\frac{\tau K_y}{\pi}} \frac{\exp\left(\frac{-(2n+1-y_D)^2}{4K_y\tau}\right) + \exp\left(\frac{-(2n+1+y_D)^2}{4K_y\tau}\right)}{2\sqrt{K_y\tau}} \right] \cdot (2n+1-y_D) \operatorname{erfc}\left(\frac{(2n+1-y_D)}{2\sqrt{K_y\tau}}\right) - (2n+1+y_D) \operatorname{erfc}\left(\frac{(2n+1+y_D)}{2\sqrt{K_y\tau}}\right) \quad (25)$$

In the second step, Eq. 23 is solved based on 9a, 11b, and boundary condition 24b:

$$\left[\frac{\partial p_{Dy}}{\partial y_D} \right]_{y_D=1} = 0 \quad (24b)$$

These conditions assume a constant flow rate at $y_D = 1$ and no flow at $y_D = 0$. The dimensionless pressure p_{Dy} is given by

$$p_{Dy} = u_1 \sum_{n=0}^{\infty} \left[2\sqrt{\frac{\tau K_y}{\pi}} \frac{\exp\left(\frac{-(2n+y_D)^2}{4K_y\tau}\right) + \exp\left(\frac{-(2n+2-y_D)^2}{4K_y\tau}\right)}{2\sqrt{K_y\tau}} \right] \cdot (2n+y_D) \operatorname{erfc}\left(\frac{(2n+y_D)}{2\sqrt{K_y\tau}}\right) - (2n+2-y_D) \operatorname{erfc}\left(\frac{(2n+2-y_D)}{2\sqrt{K_y\tau}}\right) \quad (26)$$

Based on the principle of superposition, the solution p_D to 23 and 9a, 11a, 11b is

$$p_D = p_{Dx} + p_{Dy} \quad (27)$$

Similar pressure solutions ($p_{Dx} + p_{Dy}$, $p_{Dz} + p_{Dy}$) to 27 can be obtained for 1-D flow in x and z directions, respectively. Thus, the solution for 8a is

$$p_D = p_{Dx} + p_{Dx} + p_{Dy} + p_{Dy} + p_{Dz} + p_{Dz} \quad (28)$$

The shape factor is calculated using formula 2. By assuming the same pressure gradient u_1 at six faces of a cubic rock matrix, the shape factor is

$$\sigma = \frac{6u_1}{a^2(p_{D,y=0} - \bar{p}_D) \Delta p_0} \quad (29)$$

Conclusions

The following conclusions are drawn from this study:

1. Shape factor values are time-dependent under the unsteady-state condition. The shape factor decreases with depletion time and converges to a constant value in QSS at a t_D value of 0.1.
2. When the fracture pressure is constant, the shape factor converges to $N\pi^2/L^2$ for N-dimensional flow in the rock matrix.
3. When the flow rate between the rock matrix and the fracture is constant, the fracture pressure varies with location on the rock surface. Based on the average fracture pressure, the shape factor converges to $12N/L^2$ for N-dimensional rock matrix flow.
4. The shape factors calculated from the case of constant flow rate are 1.2 times of those from the case of constant fracture pressure. The shape factor values calculated from unsteady state production are higher than those proposed by Kazemi and by Coats, but less than those by Warren and Roots.

Nomenclature

a, b, c	= length of rock matrix in x, y, and z direction, respectively
C_t	= total compressibility
d_i	= diameter of the spherical or cylindrical matrix
k	= permeability of rock matrix
K	= coefficient defined in (8b)
L	= length of rock matrix
l, m, n	= integer number
N	= number of normal sets of fractures
p	= pressure
p_m	= volumetric average pressure of rock matrix block
q	= flow rate between fracture and rock matrix
r	= radius of the spherical or cylindrical matrix
u_1	= constant pressure gradient
V	= bulk volume of rock matrix block
μ	= fluid viscosity
σ	= shape factor
τ	= dimensionless time, defined in formula (14)
ϕ	= rock porosity
π	= 3.14159

Subscripts:

D	= dimensionless term
f	= fracture
i	= initial condition
m	= rock matrix
x, y, z	= Cartesian coordinate

References

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 2. D. W. Peaceman, Convection in Fractured Reservoirs - The Effect of Matrix-Fissure Transfer on the Instability of a Density Inversion in a Vertical Fissure, *Soc. Pet. Eng. J.* Oct. 1976, p. 269-280.
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MICROBIAL TECHNOLOGY

DEVELOPMENT OF IMPROVED MICROBIAL FLOODING METHODS

**Cooperative Agreement DE-FC22-83FE60149,
Project BE3**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$320,000**

**Principal Investigator:
Rebecca S. Bryant**

**Project Manager:
Rhonda Patterson Lindsey
Bartlesville Project Office**

Reporting Period: April 1 - June 30, 1993

Objective

The objective of this project is to develop an engineering methodology for designing and applying microbial methods to improve oil recovery.

Summary of Technical Progress

Microbial mechanisms that have been shown by NIPER to be important for oil mobilization include gas and surfactant production. It is important to determine the contribution of microbial gas and surfactant production to

oil mobilization. In this regard, experiments with computed tomography(CT) and nuclear magnetic resonance imaging (NMRI) and an X-ray/microwave relative permeability apparatus may provide information to assist in determining the effect of these metabolites in porous media. To date, there are no reports in the literature where such experiments have been conducted with microbial formulations. The only reported relative permeability data for microbial formulations were obtained by NIPER's BE3 research program.

Work on this project has included the continuing development of a three-dimensional, three-phase, multiple-component numerical model to describe microbial transport phenomena in porous media. Initial efforts have focused on incorporating the most important phenomena for which mathematical models or correlations are available or can be available in a reasonably brief period of time.

Work for FY93 has continued to develop laboratory experiments to refine the model, not only with the above parameters, but also for obtaining data to incorporate microbial oil recovery mechanisms. Mechanisms considered to be important for oil recovery include changes in microscopic properties such as interfacial tension, wettability, and adsorption that govern oil mobilization and affect fractional flow and relative permeabilities. Other oil recovery mechanisms traditionally associated with fluid flow changes include polymer and biomass production by microorganisms.

A second experiment was completed using the NMRI apparatus. Microorganisms can be retained in porous rock by several possible mechanisms. High resolution NMR can image the fluids in the pore space at pore-scale resolution. By comparing before and after images of the pore space after microbial growth and activity, it may be possible to identify sites of microbial influence from

Fig. 1 Pore structure in a selected region from a Bentheim sandstone core plug imaged by NMRI, showing the thin layer of water adjacent to the grain surface with the bulk water and rock grains made transparent. The three later figures show progressive changes in the apparent pore system caused by growth of the polymer-producing microbes over time.

growth or metabolite production on fluid distribution. A micro core plug of Bentheim sandstone was used to evaluate the effects of a polymer-producing microorganism, *Leuconostoc mesenteroides*. This species produces polymer when fermenting sugar and should not produce copious amounts of gas. A previous micro core plug experiment was conducted with NIPER 7, a *Clostridium* that produces large amounts of carbon dioxide. The purpose of using *Leuconostoc* was to compare results with those of the previous core plug experiment. The NMRI results showed that changes in fluid distribution occurred

over time in the presence of the *Leuconostoc* microorganisms. Some areas within the pore system of the core plug were occupied by microbial growth, reducing the pore volume. Other areas revealed some apparent expansion of local pore space. After the imaging experiments were completed, the core plug was flushed with brine. Very slow flow rates were observed, indicating a significant obstruction of the pore network. This was not observed when the *Clostridium* core plug experiment was conducted. Surfaces of the pore space also appeared

smoother after the *Leuconostoc* treatment when compared to the brine alone (Fig. 1).

Several retention experiments were conducted this quarter using glass beadpacks. Fluorescein tracer tests were conducted before and after the injection of microorganisms, and the results were consistent with tracer tests conducted in Berea sandstone, which showed that virtually 100% of the tracer was recovered. One beadpack with a permeability of 1.3 darcies was injected with 1.2 PV of NIPER 6 (*Clostridium*), and 68.5% of the microorganisms were recovered in the coreflood effluent.

A second retention experiment was performed using a beadpack with a permeability of 910 mD. The beadpack was injected with 1.2 PV of NIPER 6. In this test, 31.5% of the microorganisms were recovered. These results were compared to previous retention tests using NIPER 6 in which 1.2 and 1.5 PV were injected into 900 mD Berea sandstone. Figure 2 shows the microorganisms recovered in two Berea sandstone cores and the glass beadpack. When these data were compared to adsorption studies using glass beads and crushed Berea sandstone, it was observed that the microbial cells were adsorbing much less on the glass beads than the Berea. This was expected since there were probably less adsorption sites on the glass beads for the microbial cells. The breakthrough of the microbial cells in the glass beadpack experiments was faster than that in the Berea sandstone. Other experiments are in progress to compare the adsorption and microbial cell retention phenomena.

The results of previous experiments showed considerable retention of NIPER 6 cells in porous media, both from adsorption on the rock and from filtration. Microbial cells that produce polymer may have slightly different cell surfaces that may adsorb or retain differently in porous media. Conducting retention tests and coreflooding studies with polymer producers will demonstrate whether there are differences in microbial cell retention and how these differences might relate to improved oil production. A retention experiment using a polymer producer was

Fig. 2 Retention of microbial cells in Berea sandstone cores and a glass beadpack.

completed. The results were inconclusive due to contamination by other microorganisms. A coreflood to evaluate oil recovery with the same polymer producer was also completed. However, the results showed no significant flow resistance increase across the core, nor any additional oil recovery when compared to a non-polymer producing microbial coreflood.

Nutrient experiments were conducted with several consortia of microorganisms to determine which nutrient is most effective in stimulating polymer production. The most favorable polymer-producing consortium was a mixture isolated from oilfield slime. The most favorable nutrient was tryptic soy broth mixed with 4% corn syrup. This inoculum will be used for corefloods to determine the pressure drop across the core during flooding and also oil production.

Results from BE3 research were presented this quarter.¹

Reference

1. A. K. Stepp, R. S. Bryant, and K. M. Bertus, *Basics of Microbial EOR Processes*. Presented at the Technology for Independent Producers Conference, Denver, CO, May 6-7, 1993.

MICROBIAL ENHANCED WATERFLOODING FIELD PROJECT

Cooperative Agreement DE-FC22-83FE60149,
Project SGP13

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Total Appropriation: \$419,000

Principal Investigator:
Rebecca S. Bryant

Project Manager:
Rhonda Patterson Lindsey
Bartlesville Project Office

Reporting Period: April 1 - June 30, 1993

Objectives

The objectives of this project are to determine the feasibility of improving oil recovery in an ongoing waterflood using microorganisms and to expand the initial pilot and determine the economics of microbial enhanced waterflooding. The scope of work for FY93 includes continued monitoring of oil production data from the Phoenix field site.

Summary of Technical Progress

The expanded MEOR project site is in Section 8, Township 24 North, Range 17E of Rogers County, Oklahoma. This site is part of Chelsea-Alluwe field in the Bartlesville formation and was initially developed soon after Delaware-Childers field. The site is being waterflooded and is owned by Phoenix Oil and Gas, Ltd. This field is in an isolated area, with virtually no other oil-producing leases nearby.

Fluorescein was injected as a tracer on June 6, 1990. Samples were collected from all 19 injection wells at 2-hr intervals the first day. Twenty-one producers were sampled 24 hr after injection of tracer, sampled daily, then weekly, once a month, and finally, quarterly. Since the second day of sampling, the tracer response has never been higher than 0.30 ppm for all but one of the wells. The pattern of the fluorescein response seems to follow the same trend as that observed during the monitoring of the Mink Unit. There was an initial quick response of tracer from some of the nearest production wells; the response then leveled out to

very low values. Fluorescein values seemed to peak at 145 d, and were monitored until the end of the molasses injection (599 d).

Wellhead injection pressures and volumes continue to be monitored and have shown no signs of plugging or any other problems. Molasses injection ceased at the end of December, 1991. Oil production data have been obtained and are graphically presented in Fig. 1 through May 1993. The incremental oil produced shows an improvement of almost 20% over the predicted hyperbolic decline. The final report for this project was completed this quarter.¹

Results of these field pilots were presented.²

References

1. R. S. Bryant, A. K. Stepp, K. M. Bertus, T. E. Burchfield, and D. M. Dennis, *Microbial Enhanced Waterflooding Mink Unit and Phoenix Field Pilots*. DOE Report NIPER-683, June 1993.
2. R. S. Bryant, A. K. Stepp, K. M. Bertus, T. E. Burchfield, D.M. Dennis, *Field Pilots Using Microorganisms*. Presented at the Technology for Independent Producers Conference, Denver, CO, May 6-7, 1993.

Fig. 1 Oil production from the Phoenix site through May 1993.

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