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Enhanced Oil Recovery

Reporting Period January–March 1996

86

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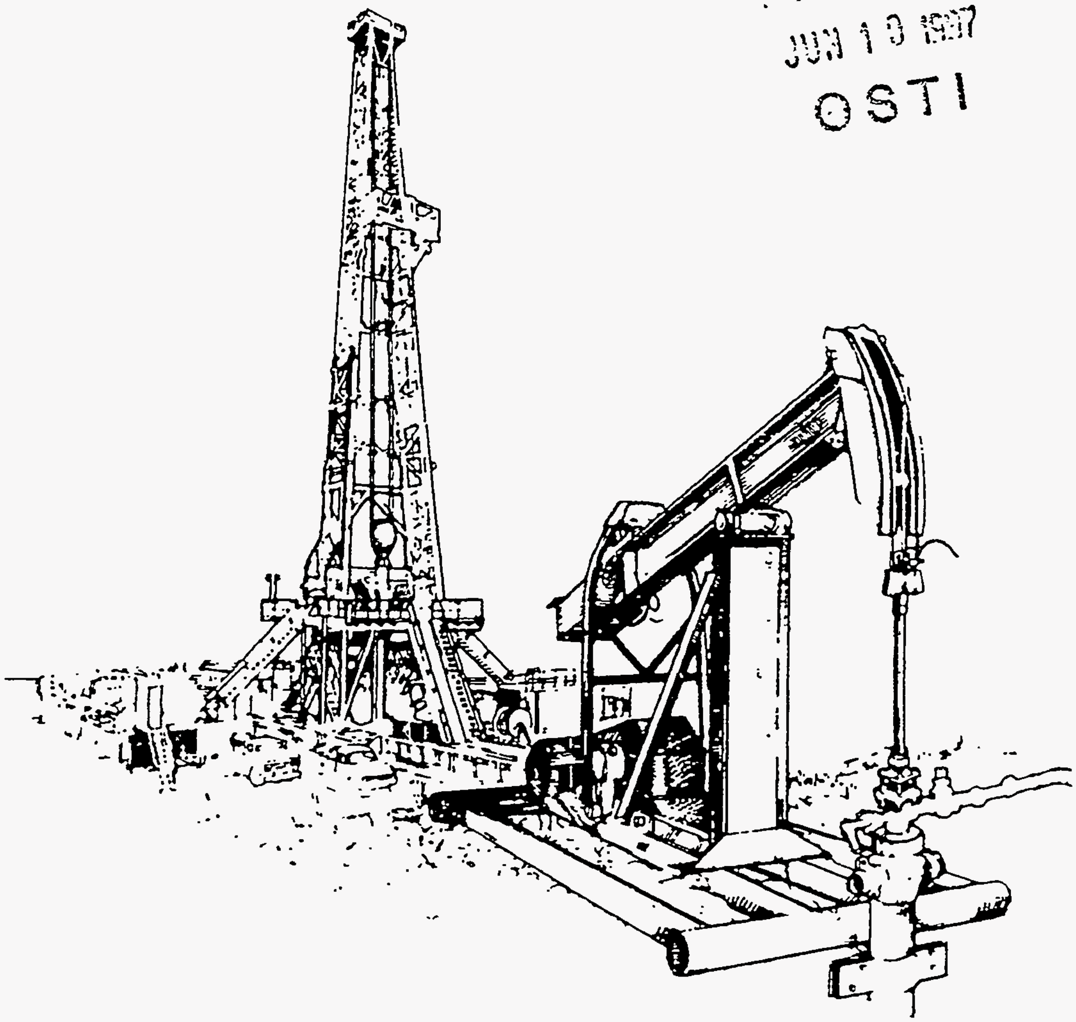
Quarter Ending March 31, 1996



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PROGRESS REVIEW NO. 86

CONTRACTS FOR FIELD PROJECTS AND SUPPORTING RESEARCH ON ENHANCED OIL RECOVERY

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Date Published - May 1997

UNITED STATES DEPARTMENT OF ENERGY

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Enhanced Oil Recovery

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GAS DISPLACEMENT—SUPPORTING RESEARCH

PRODUCTIVITY AND INJECTIVITY OF HORIZONTAL WELLS

Contract No. DE-FG22-93BC14862

Stanford University
Stanford, Calif.

Contract Date: Mar. 10, 1993
Anticipated Completion: Mar. 10, 1998
Government Award: $359,000
(Current year)

Principal Investigator:
Khalid Aziz

Project Manager:
Thomas Reid
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The objectives of the project include (1) modeling horizontal wells to establish detailed three-dimensional (3-D) methods of calculation that will successfully predict horizontal well performance under a range of reservoir and flow conditions, (2) reservoir characterization studies to investigate reservoir heterogeneity descriptions of interest to applications of horizontal wells, and (3) experimental planning and interpretation to critically review technical literature on two-phase flow in pipes and the correlation of results in terms of their relevance to horizontal wells.

Summary of Technical Progress

The third annual report[1] for the project was completed and submitted to the U.S. Department of Energy (DOE).

A detailed report on the development and testing of the Stanford mechanistic multiphase flow model has been written. Another comprehensive report on the recently developed general model for single-phase wellbore flow is in preparation. These two documents will soon be submitted as technical reports to DOE. Work on the design of the next phase of the wellbore experiments with the use of wire-wrapped screens has begun.

Example flow problems are being solved by the 3-D flexible grid simulator (FLEX) as testing and documentation of this code continues.

Work on the application of horizontal wells in gas and condensate reservoirs has progressed. The available methods and models are being critically evaluated with the aid of simulation runs.

Research work on the development of coarse-grid methods to study cresting in horizontal wells continued. Correlations for optimum grid size, breakthrough time, and post breakthrough behavior (i.e., water/oil ratio) are being developed and tested for the problem of water cresting.

Work on coupling between reservoir and the wellbore is progressing. The previous constraint of using a constant productivity index has been removed. A simple model for computing the optimum well length based on maximizing net revenue has been developed. The coupling method is now being generalized to the more realistic situations of pseudo steady-state and transient behavior.

Work on obtaining exact well models for a horizontal well or a well of any general profile continued. The developed code has been successfully evaluated against a commercial simulator (Eclipse) and other in-house simulators for many test problems. The code is currently being extended to handle cases involving many wells. A report describing the progress made on this activity was prepared.

Reference

1. K. Aziz et al., Productivity and Injectivity of Horizontal Wells, *3rd Annual Report to the U.S. Department of Energy*, Stanford University, pp. 51-53, 1996.

IMPROVED EFFICIENCY OF MISCIBLE CO_2 FLOODS AND ENHANCED PROSPECTS FOR CO_2 FLOODING HETEROGENEOUS RESERVOIRS

Contract No. DE-FG22-94BC14977

New Mexico Institute of Mining and Technology
Petroleum Recovery Research Center
Socorro, N. Mex.

Contract Date: Apr. 14, 1994
Anticipated Completion: Apr. 13, 1997
Government Award: $324,126

Principal Investigators:
Reid B. Grigg
David S. Schechter

Project Manager:
Jerry Casteel
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this experimental research is to improve the effectiveness of carbon dioxide (CO_2) flooding in heterogeneous reservoirs. Activities are being conducted in three closely related areas: (1) further exploration of the applicability of selective mobility reduction (SMR) in the use of foam flooding, (2) possible higher economic viability of floods at slightly reduced CO_2 injection pressures, and (3) taking advantage of gravitational forces during low interfacial tension (IFT) CO_2 flooding in tight, vertically fractured reservoirs.

Summary of Technical Progress

CO_2–Foams for Selective Mobility Reduction

During the study of CO_2–foam, a number of systems have been found in which mobility reduction is not simply proportional to rock permeability. This abnormal behavior is referred to as SMR. Researchers here are exploring systems where SMR favors more uniform sweep by promoting the same flow velocity in both high- and low-permeability regions of the rock. This effect will be used to enhance the mobility control associated with CO_2–foam systems in reservoirs. During the past quarter, two new surfactants (Chaser CD1040™ and Dowfax 8390™) were tested. Both reduced mobility, but CD1040™ exhibited stronger SMR than Dowfax 8390™.

Additional experiments were conducted on foam mobility measurements with the same type of composite core.[1] Two different surfactants (Chaser CD1040™ and Dowfax 8390™) were used to generate dense CO_2–foam. The results are shown in Fig. 1, where the mobility of CO_2–brine or CO_2–foam is plotted against the sectional permeability along the core sample. Because the same porous medium is used for all experiments, mobility data for CO_2–brine are repeated here for reference. As described in Darcy's Law, the slope of the line (mobility vs. permeability, see Fig. 1) determined from the regression is used as an indicator to exhibit how favorable the mobility dependence of fluid is to permeability. A slope of less than one shows favorable dependence or SMR, which leads to a more uniform displacement front when the foam is flowing through a heterogeneous porous medium. When 1000 ppm of surfactant is added to the brine, the foam exhibits different degrees of SMR behavior and mobility reduction, depending on the type of surfactant (for example, the mobility reduction is less with Dowfax 8390™ as a foaming agent than with Chaser CD1040™). Also, CD1040™ shows more favorable SMR (slope of 0.78) than Dowfax 8390™ (slope of 0.98). Both foams, nevertheless, show better mobility dependence on the rock permeability as opposed to the mixture of CO_2–brine flowing through the composite core sample.

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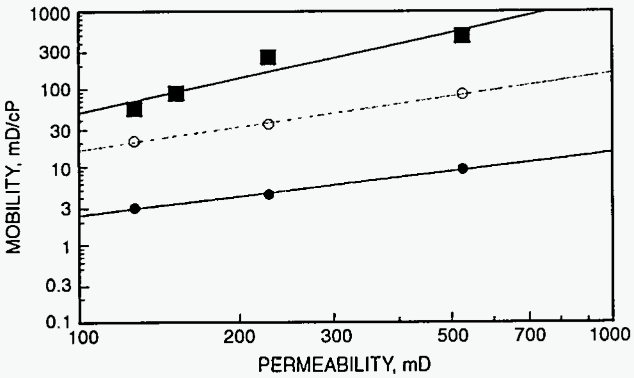

Fig. 1 Mobility dependence on permeability in a composite core. Flow velocity, 9.4 ft/d; surfactant concentration, 1000 ppm. ■, CO_2–brine (slope 1.46). ○, Dowfax (slope 0.98). ●, CD1040® (slope 0.78).

Reduction of the Amount of CO_2 Required in CO_2 Flooding

The major front-end expense of CO_2 floods is the purchase of CO_2. This task examines methods of reducing the amount of CO_2 required per barrel of improved oil recovery. Two methods to accomplish this task are being examined: (1) reduction of the mass of CO_2 required by increasing the fill volume per CO_2 mass by reducing the flood pressure and (2) improvement of sweep efficiency principally by using CO_2–foam.

Work in the areas of phase behavior, coreflooding, and the development of improved reservoir models has continued. Several fluid studies required to understand the pressure effect on CO_2–reservoir fluid-phase behavior have been completed. Coreflood studies examined the effect of flow rate, surfactant concentration, foam quality, and rock properties on the resistance factor. Finally, the development of foam models and their testing in reservoir simulators continued.

Phase Behavior Studies

CO_2–reservoir phase behavior tests in a static cell are complete on recombined Spraberry reservoir oil. This information will be used to predict miscibility development, tune equation-of-state models, and understand the role of interfacial tension on minimum miscibility pressure (MMP).

Three slim-tube tests were completed at different flow rates and pressures by injecting CO_2 into Spraberry oil that had been weathered at 138 °F. At 2100 psig, this system is still immiscible and does not appear to be near miscibility. In contrast, Spraberry separator oil developed multicontact miscibility at about 1600 psig. The loss of significant amounts of intermediate hydrocarbons (C_5 through C_{10}) raised the MMP as much as 1000 psi.

Coreflood Tests

Coreflood foam tests were performed at various CO_2 fractions (0.2, 0.333, 0.5, 0.667, and 0.8) by simultaneously injecting CO_2 and surfactant solution into a surfactant-solution-saturated core until a steady-state pressure drop across the core was obtained. The surfactant concentration was 2500 ppm. The testing flow rate was 4.2 cm^3/h. The pressure drop across the core for the foam tests was significantly higher at each CO_2 fraction than that for the baseline experiment completed previously.[1] The results indicate that the pressure drop for the foam tests increased with increasing CO_2 fraction. When the CO_2 fraction was decreased to a previously measured lower value, however, the pressure drop was greater than the original test, which indicates hysteresis. In addition, the permeability of the core could not be restored to the original value before the foam tests. Hysteresis might be caused by the effect of surfactant adsorption such that the core permeability was permanently altered. Even though the core could not be restored to the original permeability, the CO_2–surfactant solution mobilities were always higher than the baseline tests. Another new core is being tested. This new core was prepared with the use of a different firing method and should eliminate the hysteresis observed in the previous core.

Reservoir Simulations

Both MASTER and UTCOMP simulators have been successfully modified to simulate foam flooding processes where the resistance factor data are input in database format. In the validation exercises, an injection schedule that mimics an actual foam-field pilot test was used. The simulation results show an increase in the oil production rate, which is attributed to the effects of foam, and are consistent with the observation from the foam-field pilot. The results also show successful profile modification because of the presence of foam, which results in significant sweep improvement. Agreement between MASTER and UTCOMP was good. Some of the modeling results are being presented at the Society of Petroleum Engineers (SPE)/Department of Energy (DOE) Tenth Symposium on Improved Oil Recovery.

Low IFT Processes and Gas Injection in Fractured Reservoirs

Research continues in two primary areas: (1) understanding the fundamentals of low IFT behavior via theory and experiment and the influence on multiphase flow behavior and (2) modeling low IFT gravity drainage for application of gas injection in fractured reservoirs.

In the first year of the current contract, researchers here presented all the fundamental background for calculation of reservoir IFT of crude oil–gas mixtures. The calculation methodology developed was presented as a standard for industry's use in predicting IFT accurately. Evidence was presented for the conditions[2] showing that the scaling exponents can apply far from the critical point. This evidence greatly facilitates calculation of accurate IFT.

Many experiments were conducted to support the methodology by measuring the IFT of pure component liquid–vapor systems with a reservoir condition pendant-drop apparatus. The experimental data presented[1] support the assumptions necessary for simple, yet theoretically accurate, parachor calculations. During the course of low IFT studies, researchers here have focused on CO_2 gravity drainage in Berea and reservoir whole core. Such experiments have direct application to the improvement of oil recovery from naturally fractured reservoirs by gas injection.

In addition to the CO_2 IFT measurements reported,[1-3] researchers here conducted more measurements in the low IFT region for pure CO_2. Figure 2 demonstrates results from the second data set. Figure 2 indicates that, in a low IFT region, the IFT values extracted from pendant-drop profiles with the use of the conventional shape factor method are greater than expected on the basis of theoretical analysis of critical scaling. IFT of liquid–liquid systems consisting of brine (2% CaCl), heptane, and isopropanol was measured. The result, as shown in Fig. 3, demonstrates the same trend as that in Fig. 2. Next, a more accurate experiment for CO_2 IFT was conducted in which change in experimental conditions between test points was minimized. The result, plotted in Fig. 4, also shows the deviation of calculated IFT values from the theoretical trend.

As the IFT decreases below about 1 mN/m, pendant drops tend to elongate because of the increased prominence of gravity. The drop is very small at low IFT, and neck curvature is less pronounced. In this case, the shape factor method is difficult to apply because the diameter (Ds) of the drop at the elevation of the equatorial diameter (De) from the apex is strongly affected by the presence of the needle tip. Also, wetting behavior of the tip, or so-called "climbing" effect, deforms the shape of the pendant drop. It is reasonable to believe that low IFT determined on the basis of drop edge above the equator (such as the shape factor method) is erroneous in such a case.

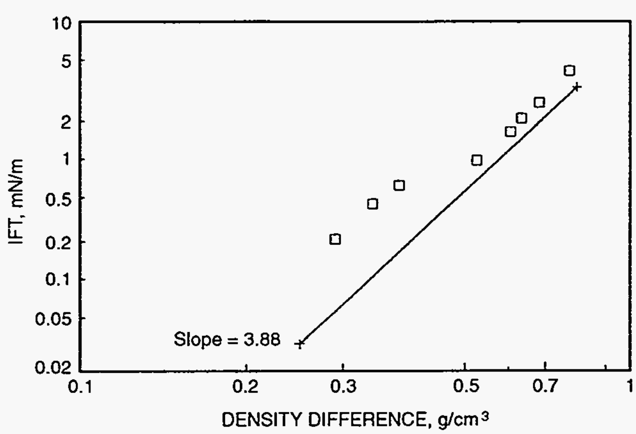

Fig. 2 Interfacial tension (IFT) vs. density difference for CO_2. Pendant drops created along CO_2 saturation curve and IFT calculated by conventional shape factor method. □, shape factor method. +, theoretical trend.

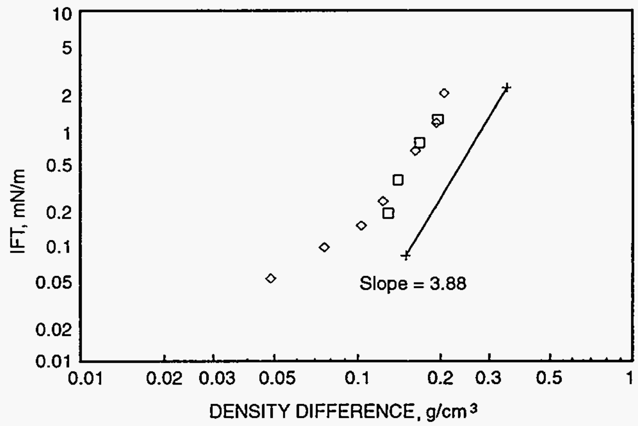

Fig. 3 Interfacial tension (IFT) vs. density difference for brine–heptane–isopropanol system. □, experiment 1. ◇, experiment 2. +, theoretical trend.

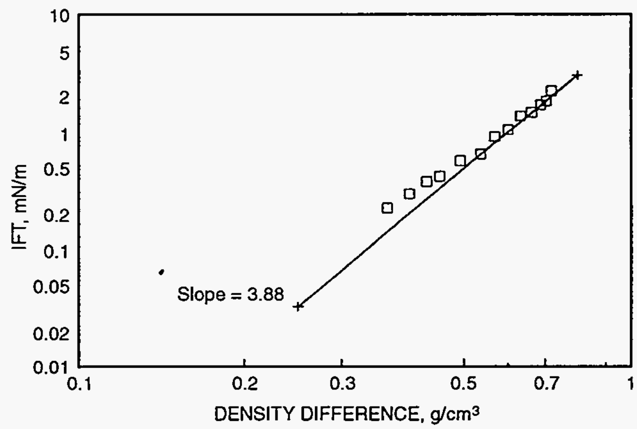

Fig. 4 Interfacial tension (IFT) vs. density difference for CO_2, minimizing change in experimental conditions between test points. □, shape factor method. +, theoretical trend.

To avoid the effect of the needle tip on low IFT measurements, researchers here developed a new method for the determination of IFT from pendant drops. The new method is formulated on the basis of equilibrium forces acting upon the lower half of the pendant drop. The hemispherical portion of the pendant-drop edge below the equator is used for IFT determination. The result of IFT determined with this new method was compared with other methods found in the literature for water, normal decane, decyl alcohol, 2,3,4 trimethyl pentane, normal heptane, hexadecane, and toluene under ambient conditions. This comparison shows very good consistency among the methods in the high IFT region (IFT > 10 mN/m). The pendant-drop generating apparatus and image processing system were used to test the new method under various conditions for water, normal decane, ethane, and CO_2. Figure 5 shows a comparison of IFT determined with the new method with that determined with

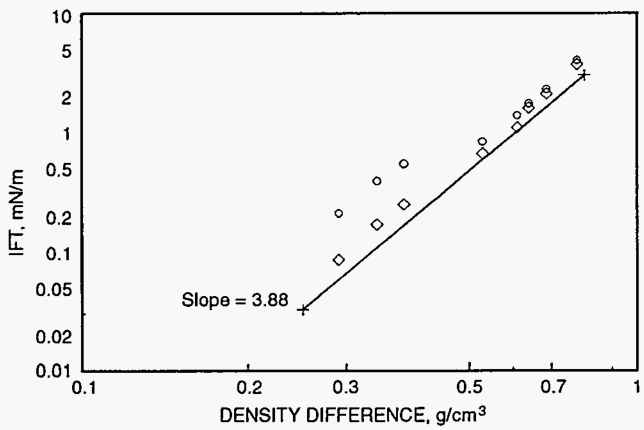

Fig. 5 Comparison of interfacial tension (IFT) vs. density difference for CO_2 with the new method and with the shape factor method. □, shape factor method. ◇, new method. +, theoretical trend.

the shape factor method. On the basis of critical scaling arguments, the new method appears to be more accurate than the shape factor method. The new method is believed to be more useful forultra-low IFT determination because it allows calculations of IFT from very small droplets so long as the droplets have equators developed.

Technology Transfer

During the past quarter, six SPE papers were written, two of which have been presented orally[4,5] and the other four will presented during the next quarter.

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1. F. David Martin, Reid B. Grigg, and David S. Schechter, *Improved Efficiency of Miscible CO_2 Floods and Enhanced Prospects for CO_2 Flooding Heterogeneous Reservoirs,* DOE Contract No. DE-FG22-94BC14977, Quarterly Report, October 1–December 31, 1995.
2. Reid B. Grigg, John Heller, and David S. Schechter, *Improved Efficiency of Miscible CO_2 Floods and Enhanced Prospects for CO_2 Flooding Heterogeneous Reservoirs,* DOE Contract No. DE-FG22-94BC14977, Annual Report, 1995.
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4. J. S. Tsau and J. P. Heller, *How Can Selective Mobility Reduction of CO_2–Foam Assist in Reservoir Floods?*, paper SPE 35158 presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Tex., Mar. 27–29, 1996.
5. H. Yaghoobi and J. P. Heller, *Effect of Capillary Contact on CO_2–Foam Mobility in Heterogeneous Core Samples*, paper SPE 35169 presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Tex., Mar. 27–29, 1996.

THERMAL RECOVERY—SUPPORTING RESEARCH

RESEARCH ON OIL RECOVERY MECHANISMS IN HEAVY OIL RESERVOIRS

Contract No. DE-FG22-93BC14899

Stanford University
Petroleum Research Institute
Stanford, Calif.

Contract Date: Feb. 8, 1993
Anticipated Completion: May 6, 1996

Principal Investigator:
William E. Brigham

Project Manager:
Thomas Reid
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The goal of the Stanford University Petroleum Research Institute (SUPRI) is to conduct research directed toward increasing the recovery of heavy oils. SUPRI is working in five main areas:

1. Flow properties studies—to assess the influence of different reservoir conditions (temperature and pressure) on the absolute and relative permeability to oil and water and on capillary pressure.
2. In situ combustion—to evaluate the effect of different reservoir parameters on the in situ combustion process; this project includes the study of the kinetics of the reactions.
3. Steam injection with additives—to develop and understand the mechanisms of the process using commercially available surfactants for reduction of gravity override and channeling of steam.
4. Formation evaluation—to develop and improve techniques of formation evaluation, such as tracer tests and pressure transient tests.
5. Field support services—to provide technical support for design and monitoring of U.S. Department of Energy (DOE)-sponsored or industry-initiated field projects.

Summary of Technical Progress

Flow Properties Studies

The positioning system for scanning in vertical mode is being built. The final design is now complete, and construction of the platform and positioning system started in February 1996. The construction is progressing on schedule. The scanning experiments in vertical position should start in the summer of 1996. A user guide for computerized axial tomography (CAT) scanner users is being written. This guide, which is now in the draft stage, will be periodically updated and will cover both software and hardware. A technical report will encompass the most useful features of this guide.

Construction of the equipment for the steam–water and nitrogen–water relative permeability studies is complete. The nitrogen–water preliminary data are described in Ref. 1. Several attempts to start the steam runs were foiled by leaks between the core and the epoxy resin surrounding it. Changes in the type of epoxy were made, and results are expected in the summer of 1996. A report summarizing the results to date will be published in the fall of 1996.

In Situ Combustion

The report describing five in situ combustion tube runs with Saudi tar and metallic additives is in the final draft stage and will be submitted for review in the summer of 1996. This report investigates the effect of various concentrations of iron nitrate additive on the combustion of Saudi tar. A concentration of 5% by weight or more appears to be needed in the conditions of the experiments for high-temperature combustion and burning front propagation.

Analysis of the two combustion tube runs performed on the oil containing sulfur is still in progress and will be the topic of a separate publication.

Steam Injection with Additives

Interpretation is complete on the waterflood and steamflood experiments in the three-dimensional model with oil present. Accurate data were obtained by combining the CAT scanner data and mass and heat balances on the model. The error analysis is still in progress. A preliminary report on these results is expected by summer 1996.

The paper on the steam injection experiments in fractured media was accepted for presentation at the Society of Petroleum Engineers (SPE/DOE) meeting on Enhanced Oil Recovery in April 1996.[2]

Observations of foam flow at low surfactant concentration in realistic-size silicon micromodels continued. Most of the work involved improving the equipment. A new video capture system was purchased, and the hard disk of the computer attached to this project was expanded. New micromodels of depth varying between 15 and 35 μm have been manufactured and will be tested in the near future.

Two new researchers are continuing this project—one will study three-phase flow mechanisms at the pore level and the other will study oil–foam interactions. A literature review on this topic is now complete, and experiments will start next quarter.

Formation Evaluation

No work was performed during this reporting period.

Field Support Services

Work done on the steam drive project in Wilmington field is summarized in Ref. 3. It includes economic and risk evaluation carried out using Monte Carlo simulation on both the technical and economic variables.

A report, *Water Influx and Its Effect on Oil Recovery,*[4] was submitted to DOE for publication and indicates ways to greatly simplify water influx calculations under all possible boundary conditions and aquifer geometries.

Technology Transfer

The SUPRI Industrial Advisory Committee Annual Meeting was held at Stanford April 8–9, 1996. Eight companies are current members; several others have expressed interest in the research.

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MODIFICATION OF RESERVOIR CHEMICAL AND PHYSICAL FACTORS IN STEAMFLOODS TO INCREASE HEAVY OIL RECOVERY

Contract No. DE-FG22-93BC14899

University of Southern California
Los Angeles, Calif.

Contract Date: Feb. 22, 1993
Anticipated Completion: Feb. 21, 1996
Government Award: $150,000
(Current year)

Principal Investigator:
Yanis C. Yortsos

Project Manager:
Thomas Reid
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The objectives of this research are to continue previous work and to carry out new fundamental studies in the following areas of interest to thermal recovery: displacement and flow properties of fluids involving phase change (condensation–evaporation) in porous media, flow properties of mobility control fluids (such as foam), and the effect of reservoir heterogeneity on thermal recovery. The specific projects are motivated by and address the need to improve heavy oil recovery from typical reservoirs as well as from less conventional fractured reservoirs producing from vertical or horizontal wells.

Thermal methods, particularly steam injection, are currently recognized as the most promising for the efficient recovery of heavy oil. Despite significant progress, however, important technical issues remain open. Specifically, knowledge of the complex interaction between porous media and the various fluids of thermal recovery (steam, water, heavy oil, gases, and chemicals) is still inadequate, and the interplay of heat transfer and fluid flow with pore- and macro-scale heterogeneity is largely unexplored.

Summary of Technical Progress

Vapor–Liquid Flow

During this quarter researchers focused on the development of relative permeabilities during steam displacement. Two directions were pursued. One direction involves the derivation of relative permeabilities on the basis of a recently completed work[1] on the pore-level mechanics of steam displacement. Progress has been made to relate the relative permeabilities to effects such as heat transfer and condensation, which are specific to steam injection problems. The second direction involves the development of three-phase relative permeabilities with the use of invasion percolation concepts. Models were developed that predict the specific dependence of the permeabilities of three immiscible phases (e.g., oil, water, and gas) on saturations and the saturation history. Both works are still in progress. In addition, work continued on the analysis of the stability of phase-change fronts in porous media with the use of a macroscopic approach.

In a related study, the effect of gravity override during injection of a gas phase (such as steam) in porous media is being investigated. From published work to date, the thickness of the gravity tongue as a function of the various process parameters cannot be predicted. Researchers here are conducting an investigation for a homogeneous porous medium assuming a sharp interface between injected and displaced fluids. An exact solution for the shape of the interface has been obtained. Researchers here are now investigating the effect of the gravity number on the thickness and shape of the gravity tongue. A somewhat parallel effort is under way to understand and model the upward (unstable) displacement of an overlying liquid by an updip injected vapor. Also, researchers here are using the results of Satik and Yortsos[1] to analyze the behavior of steam displacement in a matrix-fracture system.

Heterogeneity

Work continued on the optimization of recovery processes in heterogeneous reservoirs with the use of optimal control methods. The theory addresses the injection strategy that maximizes the recovery efficiency of a multiple-well system at various defined targets (e.g., at water breakthrough or at a fixed water cut). During the past quarter, the experimental apparatus was assembled to test the theory developed. The experimental system consists of a Hele–Shaw cell with two controlled injection wells and one production well. Preliminary results have shown that the system can be reliably used to test the optimal control theory. Current work involves conducting experiments in these geometries with the use of parameters as the mobility ratio and the form of heterogeneity and improving the numerical scheme for determination of the optimal control variables.

Work continued on the development of viscous fingering models based on the concept of transverse flow equilibrium (TFE) with the use of the theory of small fluctuations. Two technical papers were written on these subjects. The first paper[2] classifies various displacement regimes in terms of the geometric aspect ratio and proposes an improved viscous fingering model for displacements of unfavorable mobility ratio. The second paper[3] deals with a specific boundary effect that appears during simulation of viscous fingering problems in geometries of large aspect ratio. A Ph.D. dissertation[4] on this subject was completed.

Work continued on the effects of correlations (for example, with the use of fractional Brownian motion statistics). The development of saturation profiles during invasion percolation with gradients (e.g., as the result of viscous or gravity forces) in long-range correlated systems is being investigated. Work was completed on the problem of inverting capillary pressure data to infer the true pore-size distribution with the use of a pore-network approach. A technical paper on this subject is in preparation. In preparation also is a technical paper on the identification of the permeability semivariogram from multiple well pressure transients. Finally, considerable advances were made in the development of a theory for the effect of the flow rate on relative permeabilities and displacements in heterogeneous media.[5]

Chemical Additives

Work continued on the behavior of non-Newtonian fluid flow and on foam displacements in porous media. Work in this area proceeds in two parallel directions: One involves the development of a generic theory for finding the minimum threshold path in a disordered system. A technical paper[6] was prepared on this subject. The other effort involves the application of this theory to pore networks to determine the conditions for foam formation and mobilization. A technical paper[7] summarizing the results obtained is in preparation.

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OIL FIELD CHARACTERIZATION AND PROCESS MONITORING USING ELECTROMAGNETIC METHODS

Lawrence Livermore National Laboratory
Livermore, Calif.

Contract Date: Oct. 1, 1984
Anticipated Completion: Oct. 1, 1996
Government Award: $350,000

Principal Investigator:
Mike Wilt

Project Manager:
Thomas Reid
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this project is to develop practical tools for geophysical characterization of oil strata and monitoring of enhanced oil recovery (EOR) processes in a developed field. Crosshole and surface-to-borehole electromagnetic (EM) methods are being applied to map oil field structure and to provide images of subsurface electrical conductivity changes associated with secondary and tertiary EOR operations. The goal is to apply surface and borehole methods for oil field characterization and monitoring of formation changes during EOR operations.

Summary of Technical Progress

Field data recently collected at Lost Hills No. 3 oil field have been interpreted with some surprising results. After more than 3 yr of steam injection, a substantial steam chest is finally beginning to form in the upper Tulare oil sand, which was the primary target of the flood. Images show that the steam chest in the upper sands has covered half the distance between the monitoring wells (about 30 m) and the reservoir is still in the process of heating up.

In another field application, crosshole EM data collected through steel casing have been interpreted to obtain the formation resistivity. A simple scheme was implemented in which the response of the casing was evaluated and subtracted from the measured data. The residual was then interpreted to obtain a model of the formation resistivity that substantially agrees with the borehole resistivity log.

Interpretation of Lost Hills No. 3 Field Survey

The latest in a series of crosshole EM measurements between observation wells DRL35E and DRL35W was completed in January of this year. This field experiment focused on measurements on the upper 100 m, which encompass the topmost of the Tulare oil sands. Earlier surveys revealed that a substantial steam chest has formed in the middle and lower members of the Tulare sands, but the upper, richer sand has shown little change.[1] Mobil engineers suggest that this may be primarily the result of higher viscosity and greater thermal inertia in this upper formation. The formation of a steam chest would therefore require considerably more time in this oil sand.

Figure 1 shows the resistivity difference of steam flooding during the past 2 yr. The image indicates a large region of decreased electrical resistivity at a depth of 50 to 65 m. This change is caused by temperature increases and saturation changes as a result of the steam injection for EOR. The zone extends for about 15 m on either side of the injection well and tends to move higher west of the injector (updip). The image also indicates that the subsurface resistivity has decreased by 25% or less in this interval. Because steamfloods typically decrease the resistivity by 50% or more, this zone may still be getting hotter and saturated with steam.

Although steam injection has been ongoing for more than 3 yr in this pattern, this is the first indication that the steam has moved in to the shallow Tulare sands, which were the primary target. These upper sands have higher porosity, lower water saturation, and greater thickness than the lower two members. Although these properties make them a more attractive resource, they also make oil recovery via steam injection more problematic because of the difficulty of injecting steam into dry, cold heavy oil.

This result is important because it indicates that long-term steam injection will eventually mobilize the shallow heavy oil that is so abundant in central California. It also shows that EM monitoring of this process can track the development of the steam injection process and thereby help manage the resource.

Interpretation of Crosshole EM Data Through Steel Casing

Mobil is waterflooding the Pliocene Monterey diatomites at the Lost Hills No. 1 oil field near Bakersfield, Calif., for improved oil recovery. The diatomites form a series of oil and gas reservoirs in onshore and offshore central California with a total potential of more than 10 billion bbl.[2] The recovery rates from water injection have been disappointing because of water channeling and reservoir bypass. For this reason,

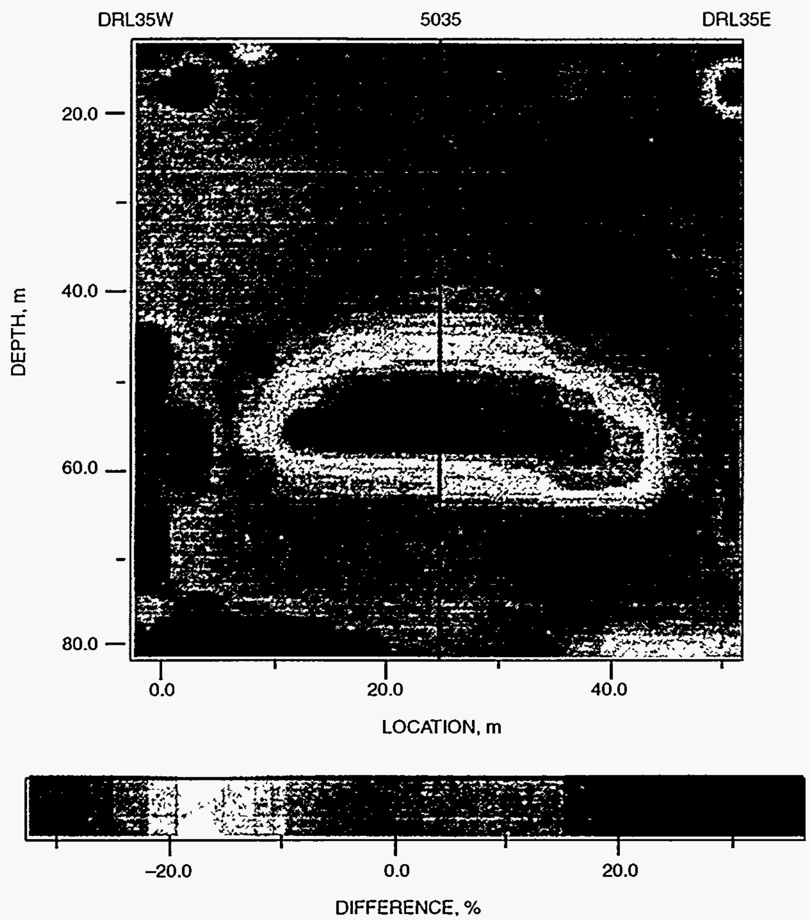

Fig. 1 Resistivity difference image at Lost Hills No. 3 using crosshole electromagnetic data. The differences are with respect to data collected in April 1994.

Mobil has installed a series of fiberglass-cased observation wells near the water injectors to monitor the water-swept intervals using repeat induction resistivity logs.

In October 1995, fiberglass observation well No. 003 and steel-cased production borehole Well No. 125-4 were used for crosshole EM measurements. The objective of this work was to track the extent of the waterflood during the injection process. Details of the field activities are described in Ref. 3.

For the first part of the experiment, the Schlumberger Multifrequency Electromagnetic Thickness (METT) logging tool was deployed in the steel-cased well to determine the casing thickness. A series of crosshole EM measurements were then made at low frequencies, where the formation effects are small but the casing effects are still significant. These EM data were interpreted with the use of a numerical code to obtain the casing conductivity.

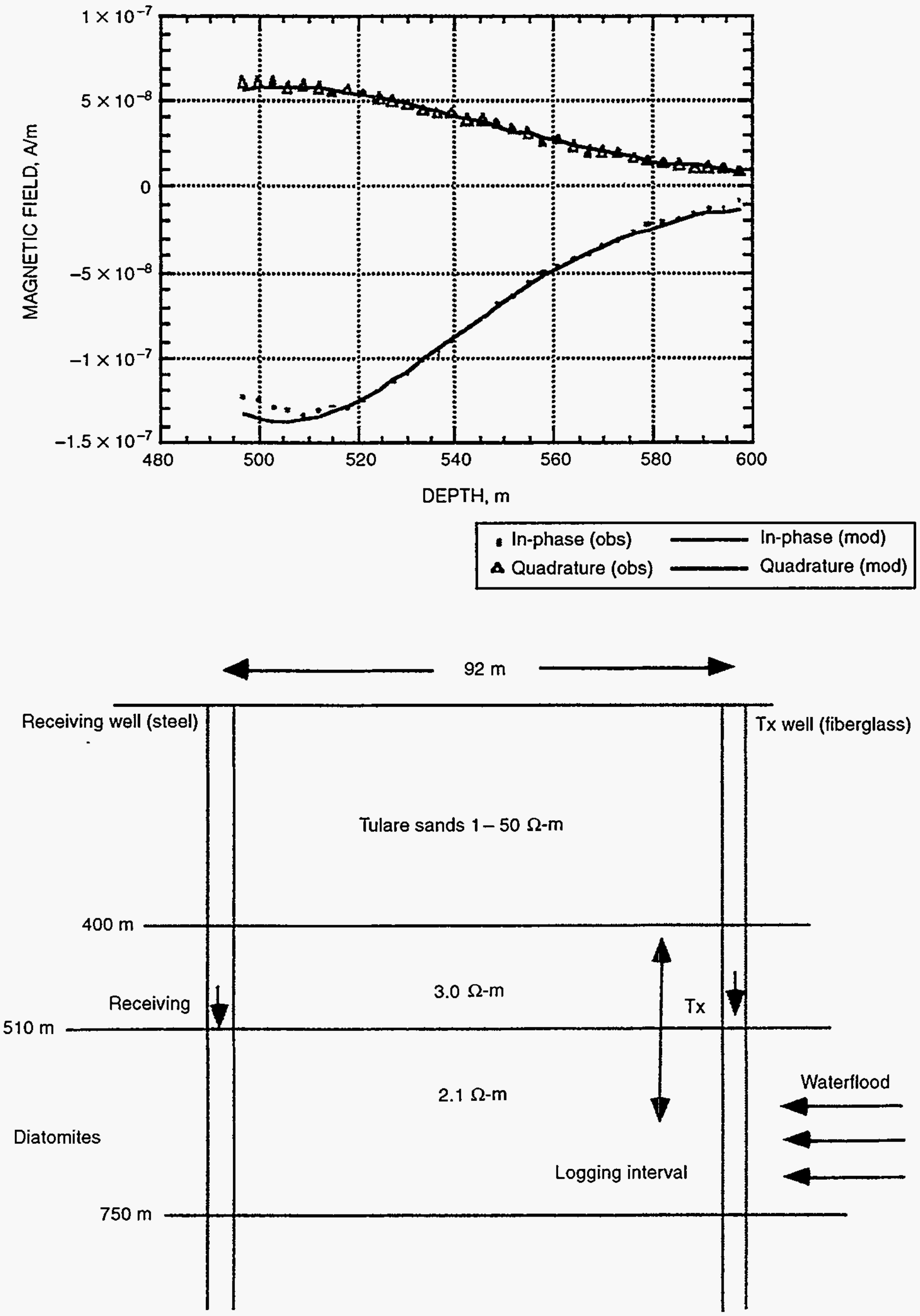

Fig. 2 Crosshole electromagnetic profile at the Lost Hills field. The data have been adjusted to compensate for the casing effect in the receiver borehole. The solid curves are for the two-layer model shown in the figure. Frequency, 200 Hz.

Next, a series of fixed frequency profiles (200 Hz) was measured in which the receiver tool was fixed at one position in the steel well, and the transmitter (Tx) was moved over a 100-m interval in the fiberglass well. At this frequency, there is substantial secondary field contribution from the formation in addition to the steel casing effect.

With the assumption that the casing and formation effects are algebraically separable, these profiles can be interpreted by adjusting the response for the free-space casing model. For a single frequency profile, this amounts to a single adjustment for the amplitude and phase; for example, for the EM profile in Fig. 2 the 200-Hz casing adjustment is a factor of 86 in amplitude and a phase shift of 350°.

After the profile is corrected for the casing effect, the data may then be interpreted by conventional techniques. For profile 1670, a least-squares inversion was applied to fit the field data to a simple two-layer model (Fig. 2). The final model agrees reasonably well with the induction resistivity log in this very uniform formation.

Technology Transfer

In March a paper entitled *Reservoir Characterization Steam Flood Monitoring in California Oil Fields* was presented to the Annex IV semiannual meeting at INTEVEP headquarters in Los Teques, Venezuela.

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GEOSCIENCE TECHNOLOGY—SUPPORTING RESEARCH

INTERDISCIPLINARY STUDY OF RESERVOIR COMPARTMENTS

Contract No. DE-AC22-93BC14891

Colorado School of Mines
Golden, Colo.

Contract Date: Sept. 29, 1993
Anticipated Completion: Sept. 30, 1996
Government Award: $753,266

Principal Investigator:
Craig W. Van Kirk

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this research project is to document the integrated team approach for solving reservoir engineering problems. A field study integrating the disciplines of geology, geophysics, and petroleum engineering is the mechanism for documenting the integrated approach. The goal is to provide tools and approaches that can be used to detect reservoir compartments, reach a better reserve estimate, and improve profits early in the life of a field.

Summary of Technical Progress

Efforts during this quarter were dedicated to history matching of the simulation model and to planning for various forecast runs. The geologic model and the engineering analysis resulted in a reservoir simulation model that is representative of the main features of the reservoir, such as the compartments and differing gas–oil contacts in each compartment. As a result of the history matching process, changes were made in the model. The economic significance of these changes, if any, will be addressed in the final report. These changes are summarized in the following sections.

Regions

The five regions for each layer separating the main compartments defined in this model are still valid. Minor changes were made in the relative location of some of the faults. The shift in the location of the faults was within the accuracy of the data used to estimate the location of the faults. This is an example in which additional information reduces some of the uncertainty. It was also determined that regions 2 and 3 are in communication and therefore have the same gas–oil contact (GOC).

Gas–Oil Contacts

The GOCs of the five regions were modified several times throughout the process of history matching. Table 1 summarizes the GOC for each of the five regions.

Well Completions

The completion reports of the wells indicate that most of the wells were perforated in layer 4, several of the wells were shot also in layer 3 and some of them in layer 5. Several wells do not have completion reports. For the simulation model, it was assumed that through hydraulic fracturing most of the wells were open in layers 3, 4, and 5. Layers 1 and 2 are sparse sand bodies, are thin, and have low porosity. For the simulation model, it was initially assumed that neither layer 1 nor layer 2 was open to production. Throughout the history matching process, it was necessary in some wells to close layer 3, in others to close layer 5, and in some to open layer 2. When performing these modifications, it was clear that these changes were consistent with the completion reports.

Initial Gas and Oil in Place

Initial conditions of gas and oil in place slightly changed because of minor local changes in thickness, but these changes are not affecting substantially the numbers reported in the last report. These values may still be refined, and therefore summaries of the final values are not presented.

Sealing Faults

As mentioned earlier, minor shifts in the location of some of the faults occurred. The changes were minor and within the accuracy of the original data.

Gathering Centers for the Simulation Model

In several cases, the production for a single well is commingled and reported on a lease basis. The production data for individual wells were created with the use of available production data, knowledge of the date at which the new wells started production, and knowledge of the initial production rate for new wells. This information was used to develop pseudo decline curves for each well on the lease for history matching purposes. For each lease, the summation of the allocated individual production is consistent with the total lease production.

The reservoir simulator incorporates nine gathering centers. Seven of the gathering centers have two wells each. One center has three wells, and one center has seven wells.

Technology Transfer

On Feb. 29, 1996, a paper entitled "Three Dimensional Seismic Reservoir Characterization of Hambert Field, Denver Basin, Colorado" was presented at the 3-D Seismic Symposium sponsored by the Rocky Mountain Association of Geologists and the Denver Geophysical Society.

On Mar. 19, 1996, a paper entitled "Structural and Stratigraphic Compartmentalization of the Terry Sandstone in the Denver Basin and the Effects of Reservoir Fluid Distributions: A Model for Exploration and Development" was presented to the Denver Geologic Society.

TABLE 1

Gas–Oil Contact (GOC) Data by Reservoir Simulation Region

Region	Datum, ft	Initial pressure, psia	GOC, ft	Bubble point pressure, psia
1	–518	1650	–518	1650
2	–505	1650	–475	1650
3	–465	1650	–475	1650
4	–400	1650	–462.5	1650
5	–505	1650	–490	1650

APPLICATION OF ARTIFICIAL INTELLIGENCE TO RESERVOIR CHARACTERIZATION: AN INTERDISCIPLINARY APPROACH

Contract No. DE-AC22-93BC14894

University of Tulsa
Tulsa, Okla.

Contract Date: Oct. 1, 1993
Anticipated Completion: Sept. 30, 1996
Government Award: $240,540

Principal Investigators:
D. R. Kerr
L. G. Thompson
S. Shenoi

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The objectives of this research are to use novel techniques from artificial intelligence (AI) and expert systems (ES) to capture, integrate, and articulate key knowledge (honoring all available "soft" and "hard" data) from geology, geostatistics, and petroleum engineering for the development of accurate descriptions of petroleum reservoirs. The ultimate goal is to design and implement a single powerful ES for use by small producers and independents to exploit reservoirs efficiently.

The project begins with the development of an AI-based methodology to produce large-scale reservoir descriptions generated interactively from geology and well-test data. A parallel second task develops an AI-based methodology that uses facies-based information to generate small-scale descriptions of reservoir properties, such as permeability and porosity. The third task involves consolidation and integration of the large- and small-scale methodologies to produce reservoir descriptions honoring all the available data. The final task will be technology transfer.

Summary of Technical Progress

Geostatistical System: Incorporation of Dynamic Constraints in a Reservoir Description Process

Three synthetic 100 × 100-grid-block data sets were generated: two using the Ingen/makecdf/SA suite of algorithms (described in the report for the last quarter for 1994) and one using the sequential Gaussian simulation (sGs) algorithm from GSLIB.[1] This report presents the results obtained using these data sets for evaluating the performance of the proposed composite objective function SA algorithm. The "truth case" description was compared with that obtained by algorithm and also with that obtained when a variogram-only objective function is used. The comparisons made are

- Visual comparisons of the images.
- Comparison of the dynamic behavior. This is accomplished by flow simulating all descriptions with ECLIPSE-100[2] and calculating the relative (percentage) errors in the flowing bottomhole pressures (BHPs) with the use of the truth case flow simulation results as the standard or basis of comparison.

The purpose, of course, is to validate that the

- Realizations generated by the modified SA algorithm more closely resemble the truth case image than that generated by the variogram-only objective function.
- Dynamic behavior of the distribution obtained from the modified approach also matches that of the truth case more closely than that of the variogram-only objective function SA run.

Figure 1 shows a visual comparison of results for data set 1. The major features of the truth case description are captured by parts b and c of Fig. 1, whereas part d does a relatively poor job.

For data set 1, nine wells were used for flow simulation. All grids were flow simulated under the same set of conditions and the flowing BHPs were compared. Errors in these pressures (actually in the change in the flowing BHPs) as a function of time for the variogram-only objective function SA run were compared with those for the composite objective function SA run.

Analyses were conducted to ascertain whether one approach was better than the other, and the results show that the methods performed about the same, which validates the use of either.

Figure 2 shows the true image for data set 2—also generated with the use of the Ingen/makecdf/SA code. The composite objective function SA run results also match the true image much better than that of the variogram-only SA run.

Having verified that the two upscaling approaches are equally good, researchers compared the modified SA algorithm (in which upscaling is performed via modified geo-metric averaging) and the variogram-only algorithm for data set 3. As shown in Fig. 3, the composite objective function results are better in matching the true image visually.

Previously the variogram models were based on the exhaustive data set. Here researchers attempted to model the variogram with the use of the conditioning data (9-point values of permeability) only. This sparsity of data resulted in

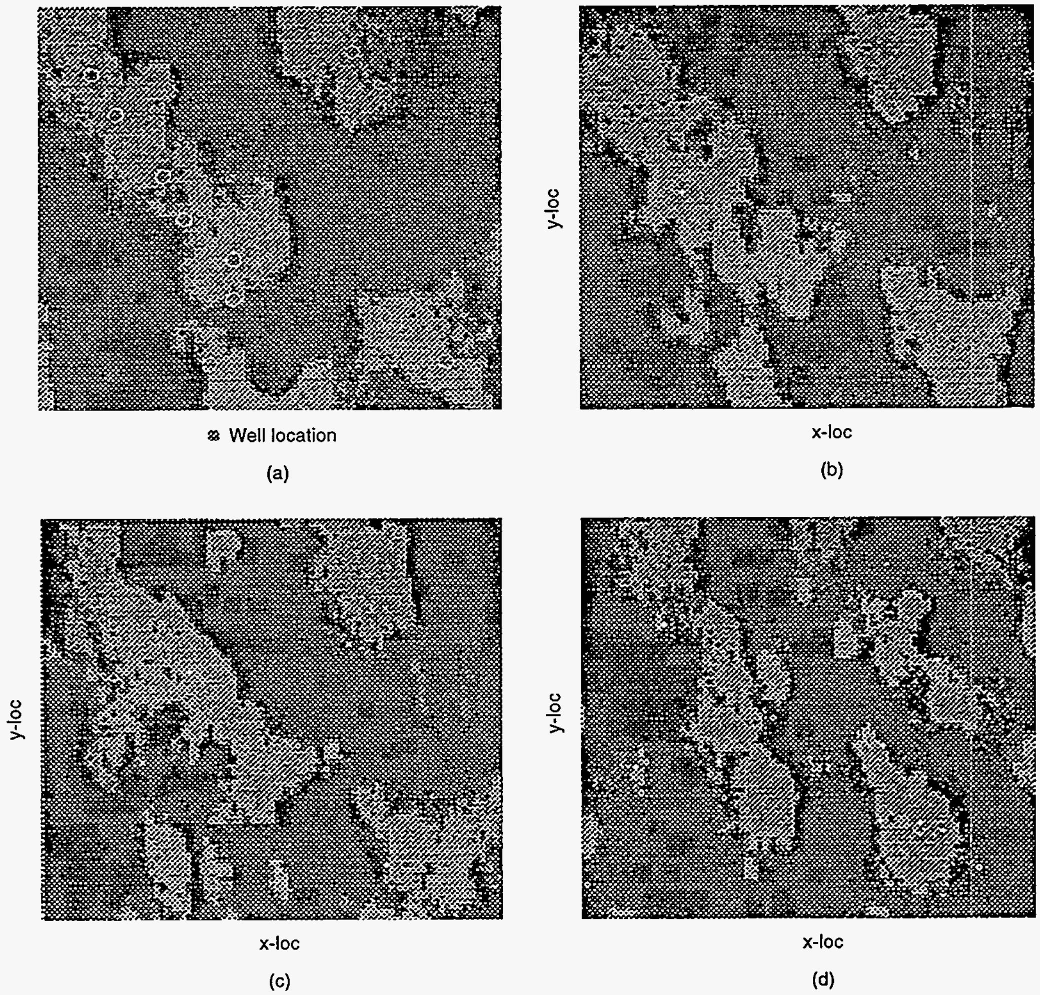

Fig. 1 (a) Truth case (true image: 1st 100 × 100 grid). (b) Modified SA run results-1 (modified geometric averaging). (c) Modified SA run results-2 (Ding). (d) Variogram-only SA run results for data set 1 (variogram-only objective function). (Art reproduced from best available copy.)

a variogram model that is very approximate and possibly inaccurate. Also, although an exhaustive data set allows anisotropy modeling, this meager data set is hard pressed to give even an isotropic model. Although there was insufficient information, one still obtains a reasonable image of the truth case. However, the results for a variogram-only SA run—with the use of a conditioning data-based (isotropic) variogram model—are unable to capture the image of the truth case, which proves the utility of the flow simulation constraint in the SA process.

Integrated Lithofacies and Petrophysical Properties Simulation

Work on the new procedure developed to generate reservoir models by simultaneously simulating the lithofacies and petrophysical properties (i.e., porosity and permeability) continues. The technique used is the conditional simulation method, which can honor the original distribution of the data and the associated spatial relationship.

The main driver of the program has been developed and compiled with the previously generated classes to obtain a working program.

Co-Simulation Program Program Structure

The co-simulation program is written in the C++ language, which allows the code to be reuseable and extendable while maintaining ease in creating a user-friendly interface. The interrelationship among the classes used in the program is shown in Fig. 4. The arrowed line indicates the inheritance relationship (e.g., between class Application and class Cosim), whereas the line ending with a circle indicates where the class is being used (for example, class Variogram is used in class Kriging, and class Kriging is used in class GaussSim).

Class Application, the main driver for the program, is developed with the use of the principle of polymorphism and dynamic binding where it contains a virtual function called DoSimulation. This virtual function is defined inside some

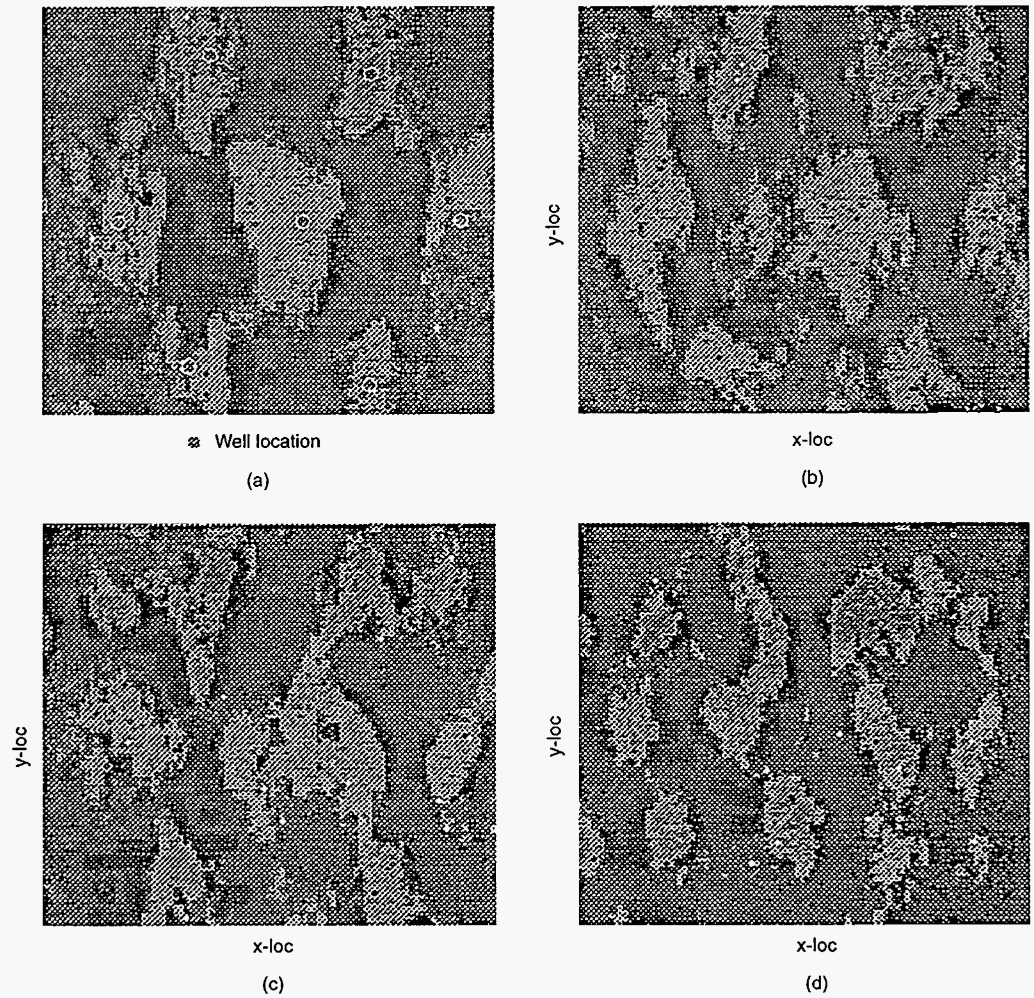

Fig. 2 (a) Truth case (true image: 2nd 100 × 100 grid). (b) Modified SA run results-1 (modified geometric averaging). (c) Modified SA run results-2 (Ding). (d) Variogram-only SA run results for data set 2 (variogram-only objective function). (Art reproduced from best available copy.)

other classes that are inherited from the Application class and dynamically bound during the execution of the program. Therefore common features of the Application class, such as development of the grid system, variogram definition, correlations among variables, etc., can be used for different techniques of simulation. At this time, there is only one class derived from the Application class (i.e., the Cosim class).

The Cosim class consists of the functions to perform the co-simulation of lithofacies and petrophysical properties. Three main classes are used in this class (i.e., the IndSim for Indicator Simulation, the GausSim for sequential Gaussian simulation, and the CondDist for conditional distribution technique for generating the permeability distribution). The class GausSim can be used either for generating porosity distributions alone or for both rock type and porosity in which the technique of Gaussian Truncated Simulation (GTSIM) is applied. In the case in which it is used for GTSIM, the IndSim is used for generating the proportion curve, which is required in transforming the Gaussian simulated result back to its indicator value. At this time the program allows the GTSIM technique only.

The Kriging class is used to perform the kriging of the unsampled value. In developing the covariance matrix, this class can either use the covariance table, which is provided by class CovTab, or directly calculate the covariance between two points given in the variogram model. The class stores the information about the variogram model input by the user and provides the routine to calculate the variogram or covariance value between two given points in three-dimensional space. The CovTab class stores the covariance value between two points, which is defined by the super block searching technique.

Simulation Results

Progress has been made in the simulation with the use of the truncated Gaussian technique as it was written in the

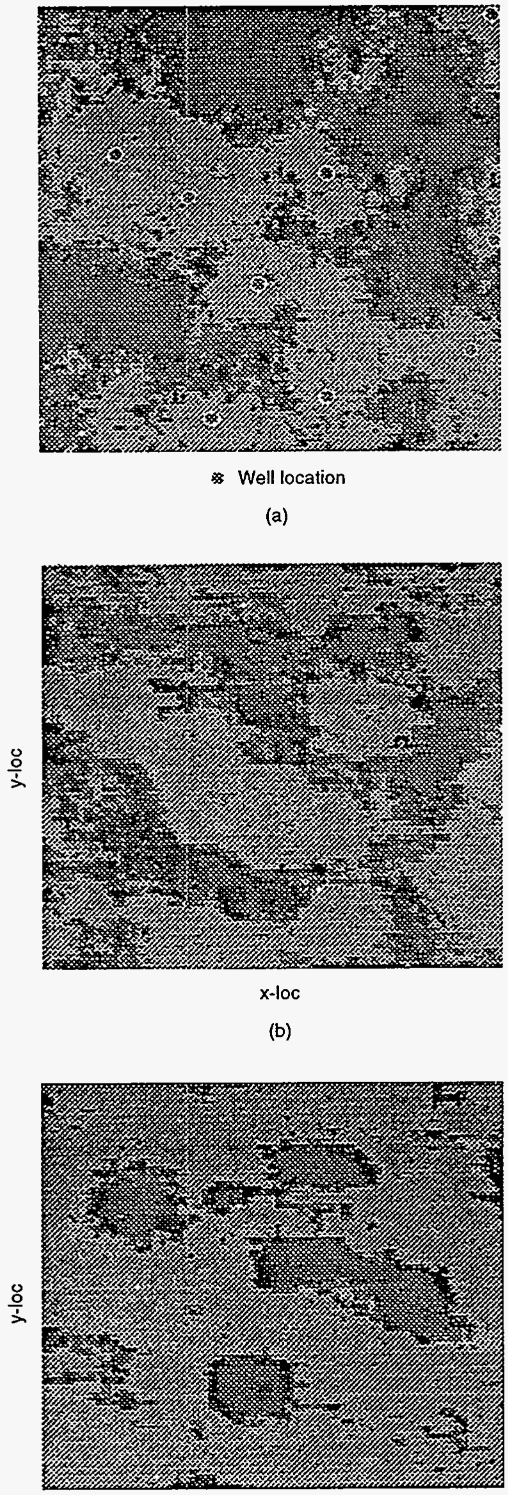

Fig. 3 (a) Truth case (truth image: 3rd 100 × 100 grid). (b) Modified SA run results-1 (2-part objective function). (c) Variogram-only SA run results for data set 3 (variogram-only objective function). (Art reproduced from best available copy.)

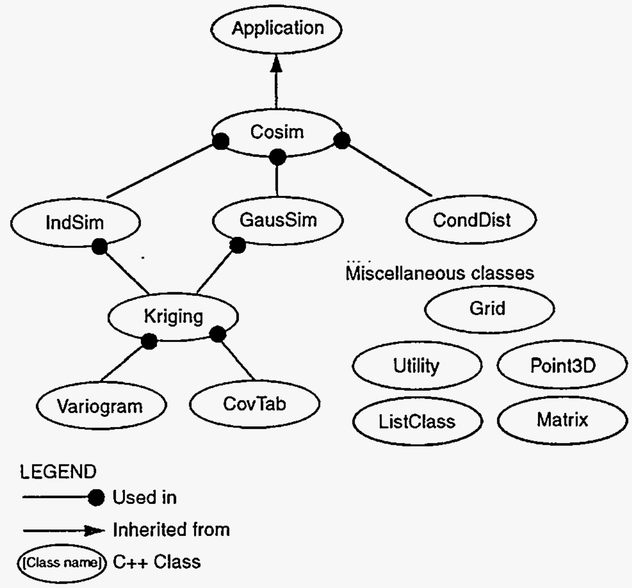

Fig. 4 Program structure.

original FORTRAN version. The result from the new program matches very well with this FORTRAN version.

Geological System: Sand Body Identification

Well Log Segmentation

Use of the low-pass filter on the well log data improves segmentation but does not improve the facies recognition performance of the neural network. Therefore only filtered well log data are used for segmentation.

Also, a new rule was added to the well log segmentation technique. This new rule calculates the shape distances between the cuts that are found with the former rules: if the distance is less than a prefixed value, one of those must be a noncut and is eliminated. The actual cut is the one that has the larger gamma-ray value.

The low-pass filtering technique and the new segmentation rule improved the performance of well log segmentation from 70 to 90%. The probability of recognizing facies correctly increased correspondingly.

Log Facies Identification

The ability of the neural network to identify log facies accurately largely depends on the accuracy of the log segmentation algorithm. Although the results have improved substantially (80% correct) with the new algorithm, the level of accuracy could still be improved. To date, the assessment of accuracy of the neural network module output is based on a single expert. Before embarking on additional changes or modifications, the research group decided that the diversity of opinion among experts should be polled.

When the results are received, a tally will be made to quantify the diversity of selection among the subjects. A cross tabulation between experience/background factors and selection outcome will also be compiled to determine any biases.

Geological System Components: Correlation of Log Curves

To further improve the resolution of the correlation matrix, researchers here are constraining the distance of the zones from the marker bed and thickness of the zones' criteria that are considered for formulating the rules. The variation in distance of the zones from the marker bed is a function of the distance between two wells and stratigraphic dip angle. The key reason for considering vertical distance from the marker bed is that, as the difference in distance from marker bed increases, its correlatability ranking goes down. Two stratigraphic units are not considered correlative if the absolute value of the difference in distance from the marker bed is greater than $x\tan\theta$, where x is the distance between two wells and θ is the stratigraphic dip angle that is set at 5° by default. Similarly, in order to constrain the thickness difference between two zones being compared, researchers impose that, when the difference in thickness goes beyond $x\tan\theta$, the zones under consideration are not correlative.

Correlation of Two Wells from the Matrix

Once the rules have determined the correlation values, the constructed matrix is analyzed by a small expert system to establish where the zones actually correlate. The analysis is based on the following facts:

- The ranking of the rules is strictly linear (i.e., a one-point difference counts).
- A maximum value for a row and column is the first choice for correlation.
- The neural network may miss cuts and thus make zones appear larger.
- Large-grain correlation, as in combining zones, is better than pinchouts.

Complete correlation between two sets of wells from Glenn Pool field was tested: Self 81 with Self 82 and 11-75 with 11-86. The logs were manually zoned, and the log facies of each zone was identified for comparison with the automated approach.

Expert System Correlation Results

Several passes of the expert system rules over the matrix were required to obtain a full correlation. The first pass generates all the values that are maximums for rows and columns. Values that are both a maximum for a row and a column result in a correlation of those zones.

If all zones are correlated, the system will then analyze the correlation. If some zones are not correlated, the system attempts to "fit" them into the currently correlated zones. This fitting is performed by examining a neighbor zone to see if its correlated zone is compatible.

Once all zones are correlated, the system analyzes the results for any problems, such as a crossover between zones. It also reevaluates values to determine if a maximum could be used in place of a current value.

Well Model Identification System

The Well Model Identification System consists of two subsystems in well model identification. Subsystem-1 uses the time–pressure data derived from well sites for model interpretation, and Subsystem-2 obtains information from geologist and uses an inference engine for model identification and selection.

Subsystem-1

When the Well Model Identification System is run, Subsystem-1 is invoked first, and it prompts the user for the name of the input file that contains the time–pressure data derived from well sites. From these data, the derivative data are generated with the use of standard algorithms. Thus the input to the system consists of time and derivative information, and the actual number of time and derivative data pairs that are used as input depends upon the test data available. The next step is to analyze these data and come up with the simplified symbolic representation for the whole plot.

Subsystem-2

This subsystem obtains information from geologist and uses an inference engine for model identification and selection. This subsystem is invoked after Subsystem-1 has completed its task. When activated, this subsystem prompts the user for input: (1) type of well, (2) fully or partially penetrating, and (3) single or double porosity. Then, input information is interpreted by evaluating conditions and rules from multiple sources.

Well Model Matching

The result from Subsystem-2 is matched against the result from Subsystem-1. If no match, the algorithm terminates with a no-match message. Otherwise, the final matched model will be passed to the third subsystem, which will calculate the nonlinear regression.

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2. *ECLIPSE 100—Black Oil Simulator*, ECL-Bergeson Petroleum Technologies, Inc., Oxfordshire, England, 1990.

ANISOTROPY AND SPATIAL VARIATION OF RELATIVE PERMEABILITY AND LITHOLOGIC CHARACTERIZATION OF TENSLEEP SANDSTONE RESERVOIRS IN THE BIGHORN AND WIND RIVER BASINS, WYOMING

Contract No. DE-AC22-93BC14897

University of Wyoming
Laramie, Wyo.

Contract Date: Sept. 15, 1993
Anticipated Completion: Sept. 14, 1996
Government Award: $239,353

Principal Investigator:
Thomas L. Dunn

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The objectives of this multidisciplinary study are designed to improve advanced reservoir characterization techniques. The objectives are to be accomplished through (1) an examination of the spatial variation and anisotropy of relative permeability in the Tensleep sandstone reservoirs of Wyoming; (2) the placement of that variation and anisotropy into paleogeographic, depositional, and diagenetic frameworks; (3) the development of pore-system imagery techniques for the calculation of relative permeability; (4) reservoir simulations testing the impact of relative-permeability anisotropy and spatial variation on Tensleep sandstone reservoir enhanced oil recovery (EOR); and (5) geochemical investigation of the spatial and dynamic alteration in sandstone reservoirs that is caused by rock–fluid interaction during CO_2-enhanced oil recovery processes.

Summary of Technical Progress

Regional Frameworks

Work in conjunction with Marathon Oil Company in the Oregon Basin field with the use of Formation MicroImager and Formation MicroScanner logs is complete. Tensleep outcrops on the western side of the Bighorn Basin are not of the quality necessary for a detailed study of stratification. This made the use of borehole imaging logs, in which stratification can be recognized, particularly attractive for the western side of the Bighorn Basin. The borehole imaging logs were used to determine the dip angle and dip direction of stratification as well as to distinguish different lithologies. Also, erosional bounding surfaces can be recognized and classified according to a process-oriented hierarchy. Foreset and bounding surface orientation data were used to create bedform reconstructions in order to simulate the distribution of flow units bounded by erosional surfaces. The bedform reconstructions indicate that the bedforms on the western side of the Bighorn Basin are somewhat different from those on the eastern side. A report has been submitted to Marathon Oil Company, the principal cost-share subcontractor.

Marine dolomitic units initially identified and correlated in the Bighorn Basin have been correlated into the Wind River Basin. Gross and net sand maps have been produced for the entire upper Tensleep in the Bighorn and Wind River basins as well as for each of the eolian units identified in the study. These maps indicate an overall thickening of the Tensleep to the west and south, which results from both greater subsidence to the west and south and greater differential erosion to the north and east.

An article entitled "Stratigraphic Analysis Utilizing Advanced Geophysical, Wireline and Borehole Technology for Petroleum Exploration and Production," which documents the North Oregon Basin field study, will be published in the Gulf Coast Section, Society of Economic Paleontologist and Mineralogist Foundation Meeting volume.

Relative Permeability Derived from Image Analysis

A process has now been developed by which petrographic image analysis can be related to relative permeability. The process also predicts relative permeability from petrographic variables through theoretical and empirical algorithms. These equations will then be used to evaluate the role of distinct sedimentologic features with respect to anisotropy encountered in the Tensleep. The algorithms will also be used to construct a detailed map of the variations in relative permeability through an eolian sequence. The results will then be placed into a geologic and spatial context to further define trends in relative permeability with respect to sedimentologic features and to the spatial orientation of these features in an eolian sand package. By placing these features into a reservoir context, better production strategies can be developed for the Tensleep. The development of these algorithms will allow operators to cheaply construct detailed maps of relative-permeability variation, on any scale, for any reservoir in the Tensleep.

Measurements of relative permeability on core plugs collected during the second field season were completed this quarter. A total of 26 samples were measured for relative permeability, bringing the total number of samples measured during the study to 60. The guidelines described by Pittman[1] and outlined in the second annual report were used to complete thin-section billet impregnation and grinding for all the samples to be used in the image analysis portion of the study. Billets that were cut from the core plugs collected during this study have been made into thin sections. A total of 100 thin sections have been made for the image analysis portion of the study. These include samples measured for relative permeability and samples that will only be subjected to image analysis. The algorithm described will be used to calculate relative permeability for these samples. Relative-permeability measurements have been made on 54 of the thin sections. A subset of these samples will be used to test the relative-permeability algorithms, whereas relative permeability of the remaining 46 thin sections will be defined only through the use of the relative-permeability algorithms. These samples will be used to further define trends in relative permeability in the Tensleep sandstone.

An algorithm has been developed for predicting oil relative-permeability curves from distinct and measurable pore-network variables. From saturation data predicted with this initial algorithm, another algorithm has been developed that accurately predicts the relative-permeability curve of water. These algorithms can be applied to quickly and cheaply predict the relative-permeability curves of both water and oil from data derived from the pore structure. The calculated data can then be placed in a sedimentologic and geometric framework to better understand how relative permeability varies with respect to sedimentologic features. The algorithm for the oil relative-permeability curve is based on the work of Mowers,[2] Ehrlich,[3] and Ruzyla.[4] Portions of these previous studies can be combined into a single equation that is based on the Carman–Kozeny equation. This equation can then be modified and used for the prediction of relative permeability. The equation used for the prediction of water relative permeability is based on work by Honarpour et al.[5] and Honarpour[6] and is an empirically derived equation that uses predicted water saturations to determine the relative permeability of water for that sample. Figure 1 shows an example of preliminary results from these equations. More testing of these algorithms must be completed, but results to date clearly show that it is possible to predict relative permeability from quantitative analysis of the pore structure with the use of petrographic image analysis techniques.

The developed algorithms will now be further tested with the use of the defined image analysis techniques. Any revisions to these original equations will be made as shown to be needed by more tests. The final developed algorithms will then be used to predict both water and oil relative-permeability curves for the remaining samples. The results can then be placed into a geologic context, and the role of each sedimentologic feature in regard to relative-permeability anisotropy can be evaluated.

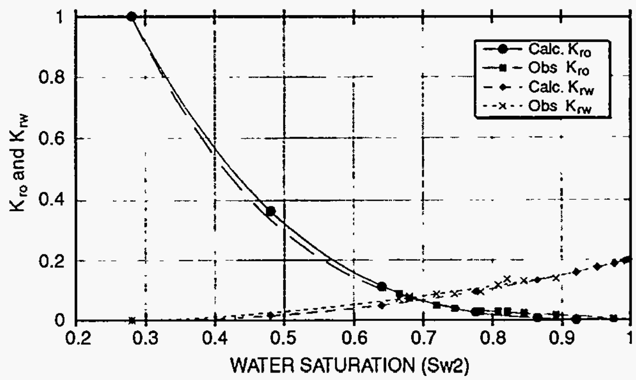

Fig. 1 Calculated and observed relative permeabilities vs. water saturation (Sw2) for both oil (K_{ro}) and water (K_{rw}). Data are from the Wilson B12 3286′v sample from the Oregon Basin field.

CO_2 Flood—Formation Alteration and Wellbore Damage

During this quarter chemical analyses of sample solutions of the fourth CO_2 core-flooding experiment, which was run in December 1995, were completed. Results showed that much anhydrite cement dissolved into solution at the early stage of the run because the nutrient solution (0.25 mol/L NaCl solution) was highly undersaturated with respect to the mineral. Concentrations of calcium and SO_4, however, decreased with reaction time, and barium concentration increased, so the solution was saturated with respect to barite throughout the run. These results contrast with those of previous runs, in which the nutrient solution originally saturated with respect to anhydrite was used. Dolomite dissolved into solution at a relatively constant rate (average alkalinity was about 16 mmol/L), whereas the solution remained undersaturated with respect to dolomite.

During this quarter the fifth CO_2 coreflooding experiment was carried out at the Petroleum Technology Center, Marathon Oil Company, Littleton, Colo. Temperature and pressure conditions were similar to those in prior runs [i.e., 80 °C and 166 bars ($P_{CO_2} = P_{total}$)]. In this experiment, Tensleep oil from the Oregon Basin oil field was used as well as subsurface cores from the Oregon Basin oil field and synthetic 0.25 mol/L NaCl solution. Before the experiment three cores were saturated with brine and then some aliquot of brine was replaced by oil. The initial water saturation of the three cores was 28, 28, and 34%. The brine, which was saturated with CO_2 gas at run conditions, was injected into the core assemblage, so oil as well as brine came out of cores with time. Thus this experiment simulated a CO_2 flood in a more realistic manner than in previous runs. The total run duration was 143 h.

Technology Transfer

The project's website for results and updates now contains the first and second annual reports as well as two recently accepted abstracts. It may be accessed at **http://ierultra1.uwyo.edu/**. In the future, this site will contain additional detailed information, data, and updates on conclusions reached.

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IMPROVED RECOVERY FROM GULF OF MEXICO RESERVOIRS

Contract No. DE-FG22-95BC14802

Louisiana State University
Baton Rouge, La.

Contract Date: Feb. 14, 1995
Anticipated Completion: Aug. 13, 1995
Government Award: $1,266,667

Principal Investigators:
W. Clay Kimbrell
Zaki A. Bassiouni
Adam T. Bourgoyne

Project Manager:
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Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

This project is a 1-yr continuation of a research program to estimate the potential oil and gas reserve additions that could result from the application of advanced secondary and enhanced oil recovery (EOR) technologies and the exploitation of undeveloped and attic oil zones in the Gulf of Mexico oil fields that are related to piercement salt domes. Work will continue in reservoir description, extraction processes, and technology transfer. Detailed data will be collected for two previously studied reservoirs: a South Marsh Island reservoir operated by Taylor Energy Co. and one additional Gulf of Mexico reservoir operated by Mobil. Additional reservoirs identified during the project will also be studied if possible. Data collected will include reprocessed two-dimensional (2-D) seismic data, newly acquired three-dimensional (3-D) data, fluid data, fluid samples, pressure data, well test data, well logs, and core data and samples. The new data will be used to refine reservoir and geologic characterization of these reservoirs. Further laboratory investigation will provide additional simulation input data in the form of pressure–volume–temperature (PVT) properties, relative permeabilities, capillary pressures, and water compatibility. Geological investigations will be conducted to refine the models of mud-rich submarine fan architectures used by seismic analysts and reservoir engineers. Research on advanced reservoir simulation will also be conducted. The research effort is being conducted in four major areas: (1) reservoir characterization research, (2) simulation of extraction processes, (3) improved oil recovery, and (4) technology transfer.

Summary of Technical Progress

Reservoir Characterization

Results of field studies and research into fine-grained submarine fans and turbidite systems are contained in a report entitled *Review of Fine-Grained Submarine Fans and Turbidite Systems*.[1]

The Landmark software necessary for performing the tasks of this project has been successfully installed. In addition, the 3-D data obtained from GECO-PRAKLA have been installed and are of very high quality. The data are being interpreted.

The additional information obtained from Mobil to upgrade and modify characterization and simulation of their reservoir is being input into BOAST III for further simulation and refinement.

Several potential representative reservoirs have been identified during the interpretation of the 3-D seismic data. Further interpretation is necessary, however.

Simulation of Extraction Processes

The current status of work in the area of modifying publicly available simulators is in a thesis.[2]

Data sets for the simulation of attic gas injection processes are being prepared to incorporate findings from architecture models that have been developed, reservoir characterization, and the laboratory results.

Data sets on the simulation of gas injection processes using nitrogen, flue gas, and carbon dioxide are being prepared to incorporate findings from reservoir characterization and laboratory results.

Data sets on the simulation of advanced waterflood processes are being prepared to incorporate findings from the architecture models that have been developed, reservoir characterization, and laboratory results.

Improved Oil Recovery

A series of experiments were outlined in the previous report; because of problems with the experiment, however, the time line given must be modified. The core holder that was to be used developed severe leaking problems at 3100 psig, the intended run pressure. Several solutions were attempted; however, because of the excessive number of ports in the core holder, the pressure tolerance was severely reduced. Researchers here have since discovered that this core holder can only be used at pressures below 2500 psig.

Another core holder was packed with sand. This core holder has five ports, as compared to twenty ports in the first core holder. Pressure testing illustrated that the new core holder can tolerate the run pressures required. It has been repacked to take care of channeling and to give a permeability and porosity similar to those of the first sandpack. It has been connected to production and injection panels and is now in service.

Currently, experiments are planned with this core at 3100 psig. However, in an effort to meet the time line set for the experimental work, several experiments for this project will be performed at 2500 psig on the first sandpack. Nitrogen will be used in these experiments; therefore the results are expected to be very similar to what would be obtained at 3300 psig because miscibility is not obtained at either pressure and the chemical interactions at both pressures are approximately the same.

References

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INTEGRATION OF ADVANCED GEOSCIENCE AND ENGINEERING TECHNIQUES TO QUANTIFY INTERWELL HETEROGENEITY

Contract No. DE-AC22-93BC14893

New Mexico Institute of Mining and Technology
Socorro, N. Mex.

Contract Date: Sept. 29, 1993
Anticipated Completion: Sept. 30, 1996
Government Award: $250,896

Principal Investigators:
Jill Buckley
William Weiss
Ahmed Ouenes

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this project is to integrate advanced geoscience and reservoir engineering concepts to quantify the dynamics of fluid–rock and fluid–fluid interactions as they relate to reservoir architecture and lithologic characterization. This interdisciplinary effort will integrate geological and geophysical data with engineering and petrophysical results through reservoir simulation.

Summary of Technical Progress

The essence of the work completed in this quarter of 1996 is summarized in the following three statements:

- Automatic log digitizing software is superior to hand digitizing.
- Laboratory wettability tests suggest that the reservoir is mixed wet.
- Results of the nonreactive tracer test were used to revise the mechanics of the wettability test design to include tracer injection below a packer.

Geologic Studies

During the last quarter all well logs were digitized with an automatic log-digitizing software package called Neuralog, which provides a more accurate numerical description of the log than is provided with the previously used hand-digitizing. The gross signatures appear quite similar, but when compared to precise hand-picked points, the accuracy of the automatic digitizing package is evident.

Attention has also been given to quality control of the information entered into the geologic database. Picks of various tops and events have been cross-checked against available paper logs to ensure accurate information for all available wells. Surfaces have been gridded and exported to various other programs, including Stratamodel, for use in visualization and simulation.

There are several possible scenarios that may have produced the lithological variations seen in the Sulimar Queen field. Researchers here are currently examining all available log, core, and production data to determine the most logical and valid scenario for the entire field. Core data indicate that the best reservoir occurs in slightly clayey sandstones in which porosity is neither occluded by too much clay nor by anhydrite. It is, however, difficult to correlate the best reservoir rock with any typical log response, a problem that is now under examination.

Reservoir Wettability

The wettability of Sulimar Queen cores has been studied with various techniques and materials. Techniques include spontaneous imbibition and low-speed centrifuge tests which have been reported previously.[1] The materials studied include preserved core from the Sulimar Queen reservoir, well 1-16, additional core from the same well that has been stored without preservation, Queen outcrop sandstone, and Berea sandstone. Table 1 gives the brine composition used, Table 2 summarizes fluid properties, and Table 3 provides many of the details of wettability tests in which Amott indices to both oil and water were measured.

Cores were prepared for wettability tests by flushing with at least 20 pore volumes (PV) of the 3/4 Sulimar Queen synthetic brine (SQSB). The unpreserved samples were evacuated for 2 d prior to saturation with brine. The preserved samples were flooded with brine immediately after the core plugs were cut. No oil was produced at this stage from any of the cores.

TABLE 1

Sulimar Queen Synthetic Reservoir Brines

Salts	Full strength, mg/L	¾ strength, mg/L
$NaHCO_3$	282	212
Na_2SO_4	4,303	3,227
$CaCl_2$	5,872	4,404
$MgCl_2$	34,917	26,188
NaCl	262,314	196,736

The cores were then immersed in the refined oil mixture. Imbibition of oil was observed from changes in core weights for the two preserved samples. No oil imbibed into the unpreserved samples. Temperature was recorded and adjustments made for the changes in fluid densities (Table 2). The brine expelled from the cores was collected and measured as

TABLE 2

Fluid Properties

Fluid	Compositional information	Temperature, °C	Density, g/mL	Viscosity, cP
Sulimar Queen crude oil (WTC) (filtered to 1 μm)		22	0.8432	9.76
		26	0.8373	8.36
	n-Pentane asphaltenes: 4% waxes: ~3% Cloud point: 57 °C	30	0.8340	7.67
Sulimar Queen crude oil (PRRC) (filtered to 0.45 μm)		18	0.8646	28.25
		20	0.8644	22.06
		22	0.8638	17.95
		24	0.8624	15.36
		26	0.8603	13.66
Refined oil mixture	80% 180–190 Saybolt viscosity paraffin oil + 20% toluene	20	0.8638	11.07
		22	0.8625	10.18
		24	0.8611	9.53
		26	0.8598	9.08
¾ SQSB	See Table 1	18	1.156	1.88
		20	1.548	1.80
		22	1.154	1.72
		24	1.153	1.64
		26	1.152	1.57

Note: WTC, Westport Technology Center analysis; PRRC, Petroleum Recovery Research Center analysis; SQSB, Sulimar Queen synthetic brine.

TABLE 3

Wettability Tests with Sulimar Queen Crude Oil Using Reservoir* and Outcrop Cores

Core ID	SQ-P11	SQ-P12	SQ-P21	SQ-P22	SQ-U31	SQ-U41	Q-O1	B300-12	B300-13
Depth, ft	2002.0-.4	2002.0-.4	2007.4-.6	2007.4-.6	1995.6	2002.5	Outcrop	Outcrop	Outcrop
Preserved?	yes	yes†	yes	yes†	no	no			
Homogeneous appearance?	no	no	yes	yes	yes	no	yes	yes	yes
Diameter, cm	3.565	3.72	3.59		3.59	3.59	3.59	3.59	3.59
Length, cm	6.77	4.34	5.96		5.78	3.18	2.77	5.85	5.85
Porosity, %		17.4			20.4	20	21.3	22.2	22.1
Nitrogen permeability, mD		5.8			138	9.3	2.43	839	815
Brine permeability, mD									
Uncleaned core	<0.1	1.5	0.34		39.7	2	19.56	438	447
Cleaned core		1.5			57.4	3.2			
Initial water saturation (S_{wi})					37.0	31.6		29.3	29.7
Oil permeability (at S_{wi})	0.97		1		40	2.3		369	355
Residual oil saturation (S_{or})									32.1
Brine permeability (at S_{or})	0.94		2.55		17.31	0.86			
Evidence of oil in core‡	yes (1)		yes (1)		yes (1)	yes (2)			
Oil Imbibition:									
Brine produced, mL									
gravimetric	0.27		0.31		0	0			
volumetric	0.3		0.2		0	0			
Oilflood:									
Brine produced (after 20 PVI), mL	3.25		0.9		5.3	2.9			
Index to oil (I_o)	0.1		0.2		0	0			0
Water Imbibition:									
Lost grains,§ g	0.1437		0.1664		0.3032	0.1322			
Oil produced (gravimetric), mL	1.24		0.74		0.41	0.79			
Waterflood:									
Oil produced (after 20 PVI), mL	1.7		0.65		3.75	0.35			
Index to water (I_w)	0.4		0.5		0.1	0.7		0.48	
I_w–I_o	0.3		0.3		0.1	0.7		0.48	

*Most of the reservoir cores have not yet been cleaned (some are still being used in subsequent experiments). After final cleaning, nitrogen permeability, porosities, and pore volumes will be measured. Saturations will then be calculated from existing data.

†Originally, these whole cores were sealed in wax. After first plugs were taken (SQ-P11 and SQ-P21), the remaining whole cores were covered in plastic and aluminum wraps and stored in plastic freezer bags.

‡No oil was produced from any of the reservoir cores when they were flushed with brine. Evidence for oil in the core comes from observations of (1) color changes during the period when cores were suspended in mineral oil to measure the extent of oil imbibition and during oilfloods with mineral oil and (2) color changes in solvents used for cleaning.

§When the cores were suspended in brine, some grains detached, changing the core weights. The total weight of these grains was measured at the end of the water imbibition experiment, and a correction was applied to the measured weights, assuming that grains were detaching at a relatively constant rate throughout the imbibition period. Queen outcrop sandstone (Q-O1) actually disaggregated during imbibition and thus was not a suitable test analog for the reservoir rock.

a volumetric check on the gravimetric results. Both are reported in Table 3. Following completion of oil imbibition, the cores were flooded with about 20 PV of the refined oil mixture so that the Amott index to oil (I_o) could be determined.[2] Changing color of the initially clear oil phase during spontaneous imbibition and forced displacement, for cores SQ-P21, SQ-U31, and especially SQ-P11, indicated that these cores did contain some crude oil.

The sequence of spontaneous imbibition and forced displacement was repeated with $^{3}/_{4}$ SQSB brine. Some grains detached from each of the reservoir cores during the spontaneous imbibition process. These were collected and weighed at the end of the experiment, and weights were adjusted accordingly. The results of spontaneous imbibition of both brine and refined oil for Sulimar Queen reservoir cores are shown in Fig. 1. Spontaneous uptake of water is shown in the positive direction; in the negative direction, the spontaneous imbibition of the refined oil mixture is shown.

All of the wettability indices (WI) measured for reservoir cores are summarized in Table 4, including the centrifuge measurements reported previously. A positive WI is more water wet, whereas a negative WI is more oil wet. The results fall into three groups: unpreserved cores, preserved cores measured by spontaneous imbibition, and preserved cores

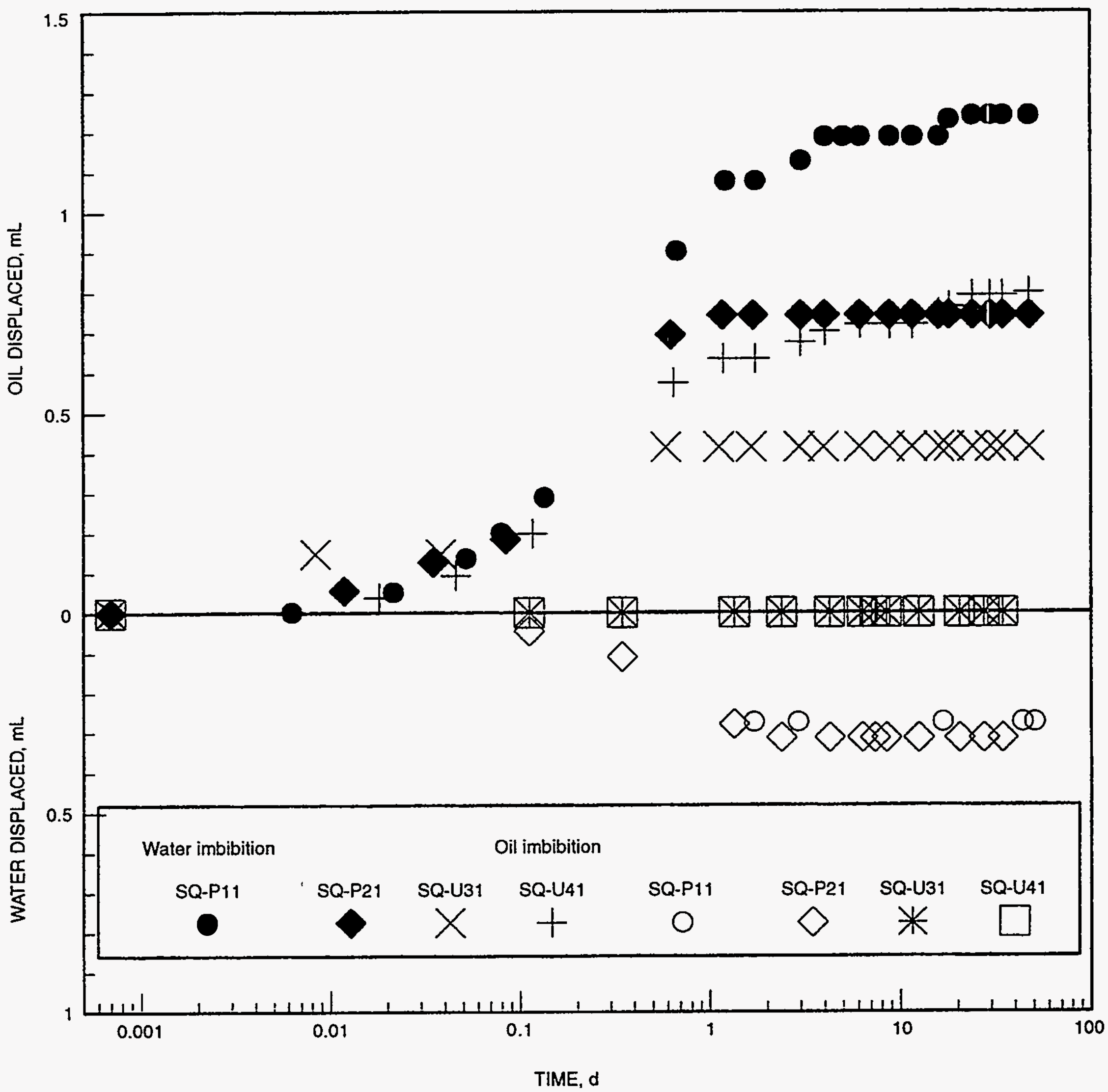

Fig. 1 Rates of spontaneous imbibition of water (3/4 Sulimar Queen synthetic brine) and oil (refined oil mixture) into Sulimar Queen reservoir cores from well 1-16. SQ-P11 and SQ-P21 were preserved at the well site. SQ-U31 and SQ-U41 were not preserved.

TABLE 4

Wettability Indices Measured by Different Methods

Core	Depth, ft	Measurement method	I_w	I_o	$WI = I_w - I_o$
SQ-W1	1996.2	Centrifuge	0.002	0.503	–0.501
SQ-W2	1998.1	Centrifuge	0.193	0.576	–0.383
SQ-P11	2002.0-.4	Spontaneous	0.4	0.1	0.3
SQ-P21	2007.4-.6	Spontaneous	0.5	0.2	0.3
SQ-U31	1995.6	Spontaneous	0.1	0	0.1
SQ-U41	2002.5	Spontaneous	0.7	0	0.7
B300-12, 13		Spontaneous	0.5	0	0.5

Note: I_w, imbibition of water; I_o, imbibition of oil; WI, wettability index.

measured by slow-speed centrifuge measurements. The unpreserved cores imbibed water but not oil. The preserved cores were all mixed wet, imbibing both water and oil. By spontaneous imbibition, cores took up more water than oil, whereas the reverse was true for fluids expelled at slow rotational speed in the centrifuge.

Preservation of the cores clearly influenced their wetting. The unpreserved cores came from above and below the zones represented by preserved cores. Some selectivity was undoubtedly applied in deciding which zones to preserve, so there may have been significant differences even before the storage period. There does appear to have been some crude oil, even in some of the unpreserved zones. SQ-U31 produced coloration in the oil phase that indicated some crude oil originally in place; SQ-U41 produced coloration in cleaning solvents at the end of the experiments. Although these samples may not have been from the prime target zone, they had been exposed to oil. It seems likely that their failure to imbibe any oil, in contrast to the preserved samples, was related to their exposure to air and consequent drying and/or oxidation during storage.

The two sets of preserved cores may differ in part because they came from different depths; the centrifuged samples were from cores buried a few feet shallower than the other two preserved samples. Differences in wetting with depth, attributable mainly to differences in initial water saturation (S_{wi}) through the transition zone, have been reported in the Prudhoe Bay reservoir.[3] A similar explanation may apply here, although the difference in height is a few feet rather than the hundreds of feet examined at Prudhoe Bay.

The main difference between spontaneous imbibition, which can be quite slow, and the accelerated method of estimating how much of each fluid would imbibe by expelling fluids at low rotational speeds, is time. If there are slow processes involved in changing wetting or detaching continuous oil from surfaces, these time-dependent processes would not be captured by the short-cut centrifuge method. Studies in better defined outcrop cores or more homogeneous reservoir cores are needed to show to what extent these two methods are comparable.

Outcrop samples of Queen sandstone were obtained for testing with the Sulimar Queen crude oil and synthetic brine. Upon exposure to the brine, the cores began to disaggregate. This is first apparent in the brine permeability that is nearly 10 times higher than the permeability to nitrogen and was even more obvious during the spontaneous imbibition test, as grains detached from the core and the size of the core continually decreased. The outcrop samples are poorly cemented with clay, whereas resevoir samples have more anhydrite cement. Alteration of wettability on contact with Sulimar Queen crude oil could not be tested in the Queen outcrop cores.

Alteration of wetting in Berea sandstone is being tested; preliminary results are shown in Table 4. The Berea is initially strongly water-wet. Exposure to Sulimar Queen crude oil (at 80 °C for 2 weeks with S_{wi} of about 30% saturation of SQSB) makes the core less water-wet. After aging in oil, one plug (B300-12) was immersed in brine. Another plug (B300-13) was waterflooded to residual oil saturation (S_{or}), then immersed in the refined oil mixture. Figure 2 shows imbibition of water and oil into these two similar Berea core plugs. Only water imbibed, more like the unpreserved samples than the preserved, mixed-wet cores. Figure 3 compares the rate of imbibition to the standard curve for strongly water-wet Berea. The time scale has been converted to a dimensionless form to account for the factors, other than wettability, which can influence imbibition rate, as proposed by Zhang et al.,[4]

$$t_D = t\left(\frac{k}{\phi}\right)^{1/2} \frac{\sigma}{(\mu_o \mu_w)^{1/2}} \frac{1}{L_c^2}$$

where t = imbibition time
k = permeability
ϕ = porosity
σ = interfacial tension
μ_o = viscosity of oil
μ_w = viscosity of water
L_c = characteristic length that depends on sample dimensions and exposure of surfaces

The rate of imbibition is significantly reduced with respect to the strongly water-wet case by exposure to Sulimar Queen oil, but the mixed-wet conditions of the preserved core are not reproduced. Petrological and mineralogical differences between the Berea and the Queen may account for differences in the extent to which wetting is altered. The outcrop sandstone is much more permeable than any of the reservoir

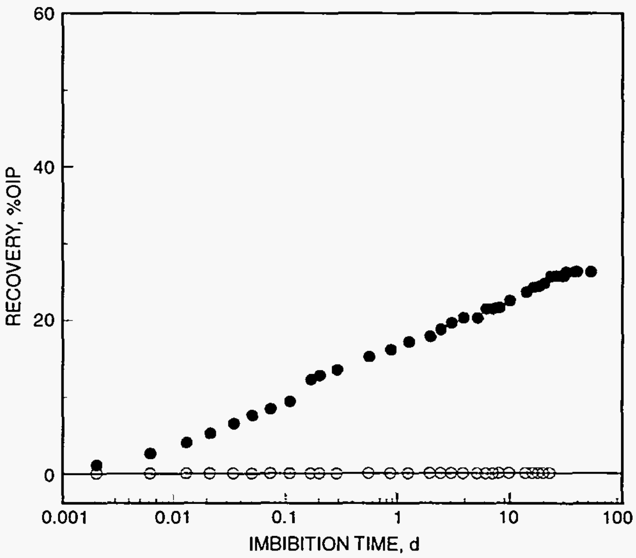

Fig. 2 Spontaneous imbibition rate for water (3/4 SQSB, B300-12, ●) and oil (refined oil mixture, B300-13, ○) into Berea cores after aging in Sulimar Queen crude oil. The cores were aged for 2 weeks at 80 °C with initial water saturation at 30%.

samples. The initial water saturation plays a role in the extent of wetting alteration and was fairly high in both the Berea cores. In Fig. 4, reported results of wettability alteration experiments with Moutray and ST-86 crude oils are shown. Three different brine compositions are included among the Moutray results. The effect of S_{wi} on wettability alteration by each oil is readily apparent. Very different trends are evident for the different crude oils. The test with Sulimar Queen crude oil appears to fall on the Moutray trend. Thus it is anticipated that less water-wet and perhaps mixed-wet conditions could be established with the Sulimar Queen oil in Berea

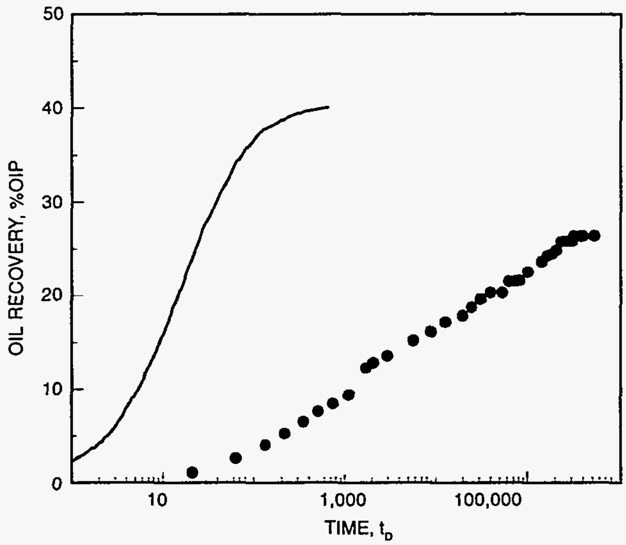

Fig. 3 Comparison of strongly water-wet water imbibition into Berea sandstone (—) with imbibition into the core treated with Sulimar Queen and B300-12 crude oil (●). Times are scaled to account for variables other than wettability that affect imbibition rate.

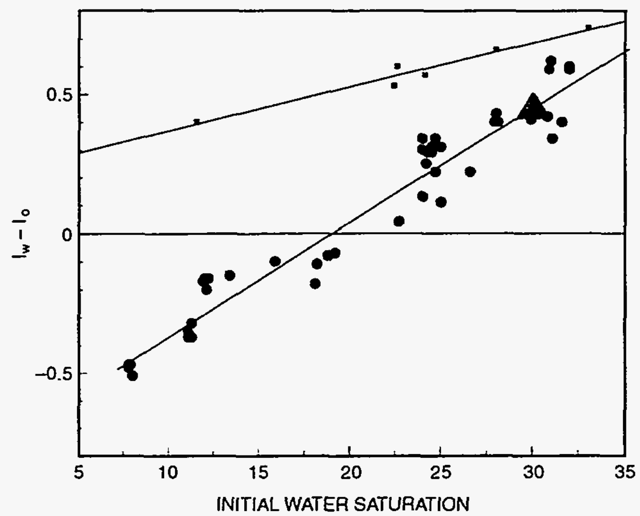

Fig. 4 Wetting alteration of Berea with Sulimar Queen oil (▲) is comparable to that resulting from aging in Moutray crude oil (●) at a similar water saturation. Moutray and ST-86 (■) data from Jadhunandan and Morrow.[5] I_w, imbibition of water. I_o, imbibition of oil.

sandstone by reducing S_{wi}. These various tests of wettability in reservoir and outcrop sandstone suggest that the Sulimar Queen reservoir is mixed-wet and that imbibition of water exceeds imbibition of oil. There was less evidence of oil-wetting in the spontaneous imbibition tests than reported for samples tested by the centrifuge technique. Whether the differences represent nonuniformity of wetting in the reservoir or differences inherent in the measuring techniques is yet to be resolved.

Field Operations

The tracer thiocyanate (CNS) analyses were completed. The produced tracer concentration profile is seen in Fig. 5 along with the average producing rate (bbl/h) as a function of cumulative production.

Note that the tracer concentration falls rapidly at about 35 bbl produced. Tracer injection was down the annulus, which has a volume of about 35 bbl. The continued addition of tracer from the annulus during the initial producing period voids this portion of the test. Tracer injection during the oil wettability test will be down the tubing with a packer set above the producing zone to minimize the afterflow problem encountered during the nonreactive tracer test.

During tracer addition and production, the bottomhole pressure at well 1-3, located 270 ft to the west of well 1-16, was monitored with an electronic gauge. The pressure history is seen in Fig. 6. Injection of the tracer was by gravity from a 100-bbl tank down the annulus. The annular fluid level continued to fall after the tank was emptied, and the pressure at the observation well increased from 784 to 785 psi before decreasing. Pumping the signal well to recover the CNS tracer resulted in a rapid decrease in the bottomhole pressure at well 1-3. Both the gravity injection rate and the producing rates varied during the test, but generally the producing rate was twice the injection rate.

The pressure difference vs. time at well 1-3 during the injection period was matched to the dimensionless exponential-intergral curve.[6] On the basis of calculations with the match points and the 4-bbl/day injection rate, the permeability is 4.8 mD. Similarly, the pressure difference curve during the production period was matched to the exponential-integral curve, and the interwell permeability was found to be 6.2 mD with a 9-bbl/day producing rate.

Technology Transfer

During first quarter of 1996, contact was made with an independent oil company with production in the Sulimar Queen formation. The company expressed an interest in applying the advanced geoscience and engineering techniques to a Queen reservoir offsetting the Sulimar Queen. The waterflood forecasting technique is of special interest because the company's properties have not been waterflooded. Similar interest has been informally expressed by other operators in the area.

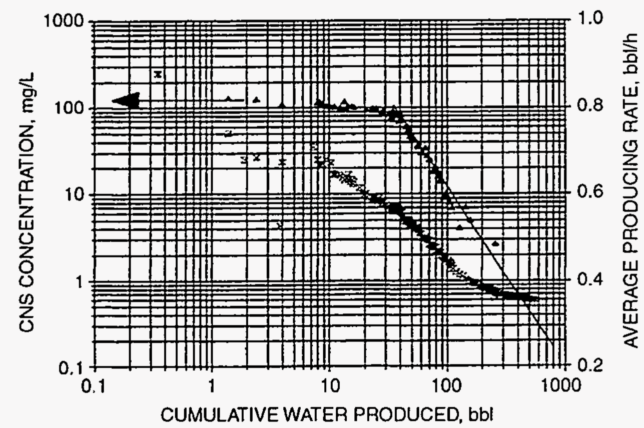

Fig. 5 **Produced tracer (CNS) concentration profile as a function of cumulative production.**

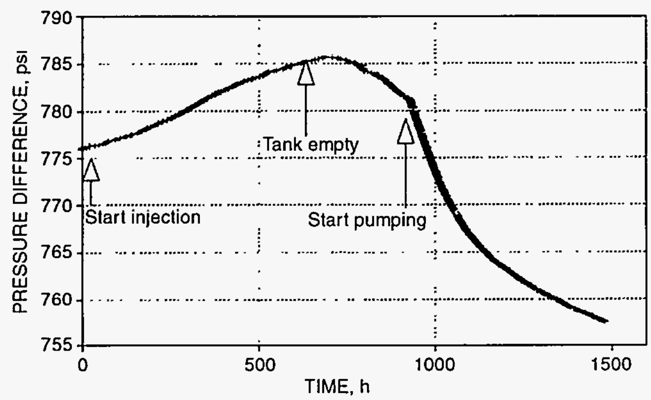

Fig. 6 **Pressure history, interference test with signal well 1-16 and observation well 1-3.**

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GYPSY FIELD PROJECT IN RESERVOIR CHARACTERIZATION

Contract No. DE-FG22-95BC14869

University of Oklahoma
Center for Reservoir Characterization
Norman, Okla.

Contract Date: Apr. 6, 1995
Anticipated Completion: Apr. 5, 1997
Government Award: $350,000
(Current year)

Principal Investigator:
Daniel J. O'Meara, Jr.

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The overall objective of this project is to use the extensive Gypsy Field laboratory and data set as a focus for developing and testing reservoir characterization methods that are targeted at improved recovery of conventional oil. The Gypsy Field laboratory consists of coupled outcrop and subsurface sites that have been characterized to a degree of detail not possible in a production operation. Data from these sites entail geological descriptions, core measurements, well logs, vertical seismic surveys, a three-dimensional (3-D) seismic survey, cross-well seismic surveys, and pressure-transient well tests.

The project consists of four interdisciplinary subprojects that are closely interlinked: modeling depositional environments, upscaling, sweep efficiency, and tracer testing. The first of these aims at improving the ability to model complex depositional environments that trap movable oil. The second entails testing the usefulness of current methods for upscaling from complex geological models to models that are more tractable for standard reservoir simulators. The third investigates the usefulness of numerical techniques for identifying unswept oil through rapid calculation of sweep efficiency in large reservoir models. The fourth explores what can be learned from tracer tests in complex depositional environments, particularly those which are fluvial dominated.

Summary of Technical Progress

This quarter the main activities involved the modeling depositional environments and upscaling subprojects. The main accomplishments were (1) construction of a deterministic model of the Gypsy Outcrop to serve as a "ground truth" model for evaluation of both existing and future geological modeling tools; (2) relaxed physics simulation on high-resolution deterministic model of the Gypsy Outcrop with several well configurations and with several possibilities for the nature of transmissibility barriers across channel boundaries; and (3) preparation of SPE paper 35477, "The Gypsy Outcrop Model for Testing Geostatistical Methods," which suggests that the Gypsy Outcrop Model and the simulations run on it can serve as a basis for a Society of Petroleum Engineers (SPE) "Comparative Solutions Project" in geostatistics.

Over the past decade, a number of geostatistical methods have emerged for modeling depositional environments. Although these methods enjoy wide acceptance, they have rarely been tested with realistic reservoir models. One reason for this is lack of quantitative data. Another is lack of consensus on what constitutes a valid test. The present study addresses both of these problems.

Fluvial environments offer a particular challenge for geostatistical modeling. The key to unlocking recovery in such reservoirs lies in a better understanding of how reservoir architecture and connectivity affect sweep efficiency. The present study entails the construction of a "deterministic" model of one such reservoir. This model describes six channels within a 20-m interval of the well-characterized Gypsy sandstone of northeastern Oklahoma. Detailed spatial distributions of reservoir properties (permeability, porosity, and lithology) have been obtained from extensive sampling and mapping of the geological units of this formation because it is exposed by strike- and dip-oriented roadcuts. In addition, 3-D data were obtained from a grid of 22 boreholes, with oriented core, drilled within 300 m behind the primary strike-oriented outcrop. This model is as complete and as densely sampled as any model of a producing reservoir is ever likely to be.

Simulations on the Gypsy Outcrop model show that waterflood recovery efficiencies can be highly variable, depending on the choice of well placement and transmissibility multipliers. Recovery efficiencies are given for the case of unit mobility ratio displacements. An important focus for comparison of various geostatistical methods should be determination of whether they can mimic the variability in recovery efficiencies displayed by such models as the present one. The criteria for evaluation of the relative merits of competing approaches should emphasize recovery efficiency rather than mere visualization of heterogeneities in porosity and permeability.

There also needs to be an SPE Comparative Solution Project in geostatistics. The Gypsy Outcrop model presented here can serve as one of several "ground truth" models for evaluation of both existing and future geostatistical methods. Comparison of flow modeling results with the use of stochastic realizations constructed from such deterministic models will permit evaluations of the sensitivity of geostatistical methods to the type and amount of data available.

Reservoir Modeling

Researchers here have constructed a single "deterministic" reservoir model of the Gypsy Outcrop. This model honors all existing data as closely as possible and represents the best understanding of the Outcrop, although it cannot be an exact description of what exists. However, the model contains real data, represents a realistic geological interpretation, and is as complete and as densely sampled as any model of a producing reservoir is ever likely to be.

There are six channels and one splaying crevasse facies within the Gypsy interval. The overbank or floodplain deposits are largely impermeable siltstone and mudstone; they may serve as partial flow barriers between channel sandbodies. Within channel sandbodies, lithofacies comprise the major heterogeneities. Four reservoir lithofacies have been defined within a typical channel sequence of Gypsy sandstone. From bottom to top, the lithofacies units are mudclast sandstone, cross-bed and plane-bed sandstone, ripple sandstone, and overbank deposit. These lithofacies have been defined on the basis of rock textures, geological constituents, and sedimentary structures.

Cross-bed and plane-bed facies exhibit the best reservoir quality, with a mean permeability of 864 mD and a mean porosity of 24.2%. The overbank facies is likely to act as a major flow barrier, although it does have a nonzero, measured mean permeability of 0.635 mD and mean porosity of 11.5%. Mudclast and ripple facies are very heterogeneous, containing both reservoir quality rock and flow barriers. The mudclast facies has a mean permeability of 73.1 mD and a mean porosity of 15.0%. The ripple facies has a mean permeability of 165 mD and a mean porosity of 20.0%.

The channels and the splaying crevasse were distributed into the 3-D model (Fig. 1) with the use of a standard software mapping package. For the first channel, the bottom surface and the isopach were mapped. The top of the first channel, also the bottom of the second channel, was determined by adding the isopach of the first channel to its bottom surface. For each subsequent sandbody, the isopachs were mapped and the top was determined by adding its isopach to the top of the underlying sandbody. For every isopach map, it was necessary to add control points to ensure that a geologically sensible result was obtained. Thus geological interpretation was imbedded into the model.

Once the channels were determined, the various facies were distributed in the following way. For purposes of the present discussion, a "sequence" is defined as a unique combination of facies and channel or facies and splaying crevasse (for example, the mudclast facies in channel 2 defines a unique sequence). With this terminology, the model consists of 24 sequences: 5 of the channels have the entire four facies defined previously, channel 6 displays only three of these facies, and the splaying crevasse consists entirely of the ripple facies. These sequences were mapped in the same way as the channels except that additional control points to guide the mapping were limited by the position of the associated channel. The resulting lithofacies distribution is shown in Fig. 2.

Each sequence has been subdivided into 0.3-m-thick layers parallel to the bottom of the sequence. These layers are truncated by the bottom of the overlying sequence. Within the 24 sequences there are 190 layers. The resolution in the areal plane is 47×48 gridblocks.

Waterflood simulations were performed in order to investigate three important effects: flow barriers, transmissibility multipliers for internal heterogeneities, and well configurations. To simplify the description of the flow, a unit mobility ratio simulator was used.

Four cases of flow barriers were simulated for an isolated, inverted five-spot configuration of wells: (1) Unimpeded flow across channel or facies boundaries; (2) no flow across channel boundaries; (3) no flow across sequence boundaries; and (4) no flow across boundaries between high- (cross beds and plane beds) and low- (mudclast, ripple, and overbank) permeability lithofacies.

Case 1 allows flow to be determined entirely by the permeability distribution irrespective of considerations of boundaries between channels or lithofacies. Case 2 sets the transmissibility multiplier to zero across any gridblock interface for which there is a change in sequence. Case 3 sets the transmissibility multiplier to zero across any gridblock interface for which there is change in sequence. Case 4 sets the transmissibility multiplier to zero across any gridblock interface between high- and low-permeability lithofacies. In all cases, there is a constant rate of injection into a central well, with four production wells, at the corners, producing at the same constant bottomhole pressure.

The geological reasonableness of these four models shows that cases 1 and 4 are the most sensible. Case 1 assumes that all the flow boundaries have been explicitly mapped, whereas case 4 accounts for the possibility of clay or shale drapes between the high- and low-permeability facies. Case 3 is the least sensible insofar as it cuts off flow whenever either the channel or lithofacies changes across interfaces between gridblocks. Case 2 requires some sort of barrier to have been deposited between channels, when the more likely situation entails one channel incising another, thus offering no impediment to sand-upon-sand contacts between channels. Case 2, however, is not far-fetched: detailed modeling of lithofacies within the channels is necessary to show sand contacts. Without such modeling it may be easy to assume the presence of barriers between channels.

Figure 3 shows the differences in oil recovery for up to 0.82 pore volume (PV) of water injected. There are substantial differences between the various cases. Case 1 shows the highest recovery and case 3 shows the lowest. The main reason for the relative positions of cases 2 and 4 is because the cross-bedded zones are fairly well connected across the model, irrespective of channel boundaries. In other words, cross-bed upon cross-bed, or good sand on good sand, contacts allow flow across channel boundaries in cases 1 and 4. These contacts are prevented in cases 2 and 3. Figures 4

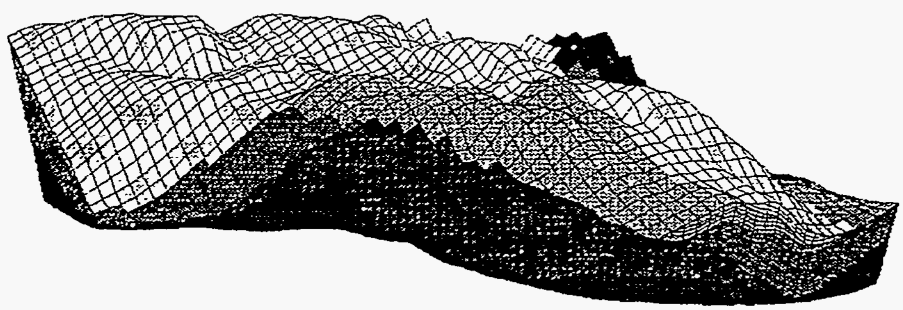


Fig. 1 Distribution of six fluvial channels within Gypsy outcrop model. (Shades of gray denote different channels). (Art reproduced from best available copy.)

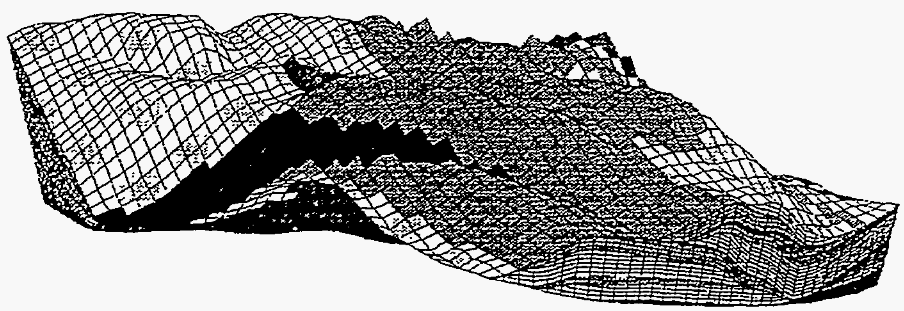


Fig. 2 Distribution of lithofacies within Gypsy outcrop model. [Shale is black, low-permeability lithofacies are dark gray, high-permeability lithofacies (such as cross beds and plane beds) are lighter shades of gray.] (Art reproduced from best available copy.)

and 5 show oil saturation profiles along cross sections emanating from the central well after injection of 0.82 PV of water. Figure 4 depicts case 1, where there is unimpeded flow, and Fig. 5 depicts case 2, where there is no flow across channel boundaries.

Researchers here have explored the consequences of impeding flow in the vertical (Z) direction for the case of an inverted five spot and a line drive directed along the channels. Z-direction transmissibility multipliers were chosen as a function of lithofacies (0 for overbank, 0.01 for mudclast, 0.02 for ripple, and 0.1 for cross beds and plane beds). Three cases were investigated: (1) Five spot with unimpeded flow, (2) five spot with Z-direction transmissibility multiplier dependent on lithofacies, and (3) line drive along channels with Z-direction transmissibility multiplier dependent on lithofacies.

Figure 6 shows the differences in oil recovery for up to 0.82 PV of water injected. Oil recovery for the five spot is 0.06 PV less with the use of the Z-direction transmissibility multipliers. The line drive recovers 0.13 PV more oil than the five spot with the use of the Z-direction transmissibility multipliers.

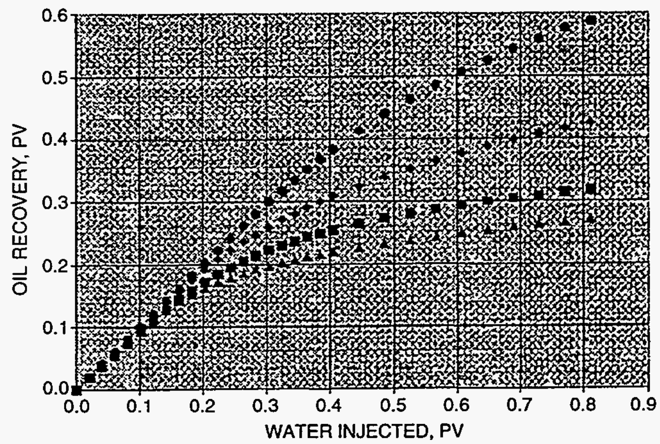


Fig. 3 Oil recovery as a function of water injected for four cases of flow in an inverted five spot: unimpeded flow across channel or lithofacies boundaries (●), no flow across channel boundaries (■), no flow across sequence (lithofacies/channel combination boundaries (▲), and no flow across boundaries between high- (cross beds and plane beds) and low- (mudclast and ripple) permeability lithofacies (♦).

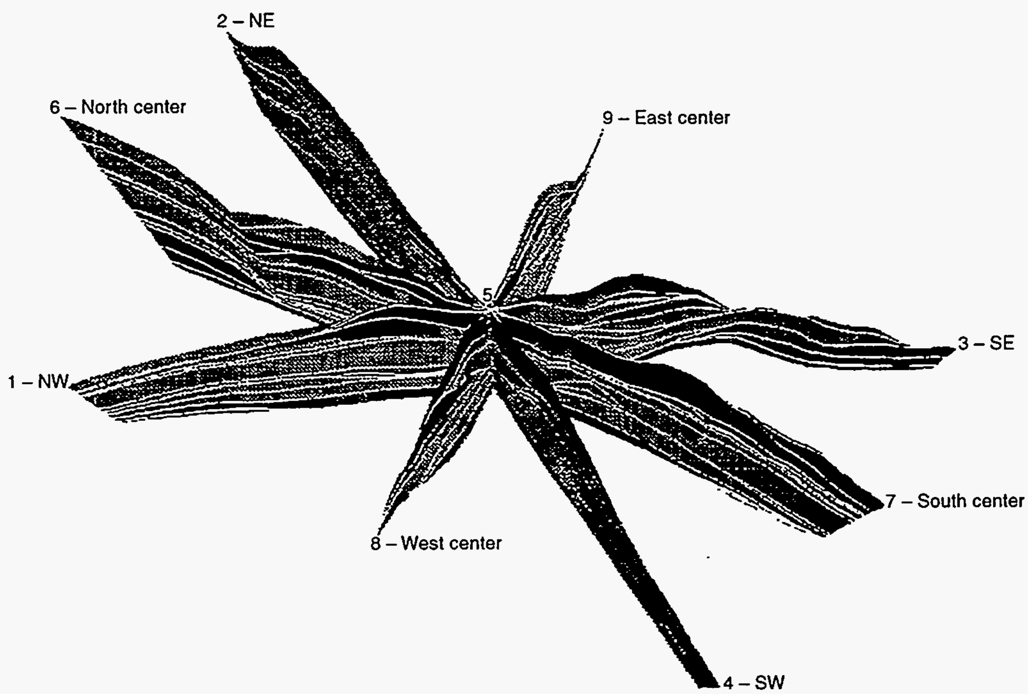


Fig. 4 Cross sections through central injector depict oil saturation (original oil is black) after injection of 0.82 PV for the case of unimpeded flow across boundaries between either channels or lithofacies. (Art reproduced from best available copy.)

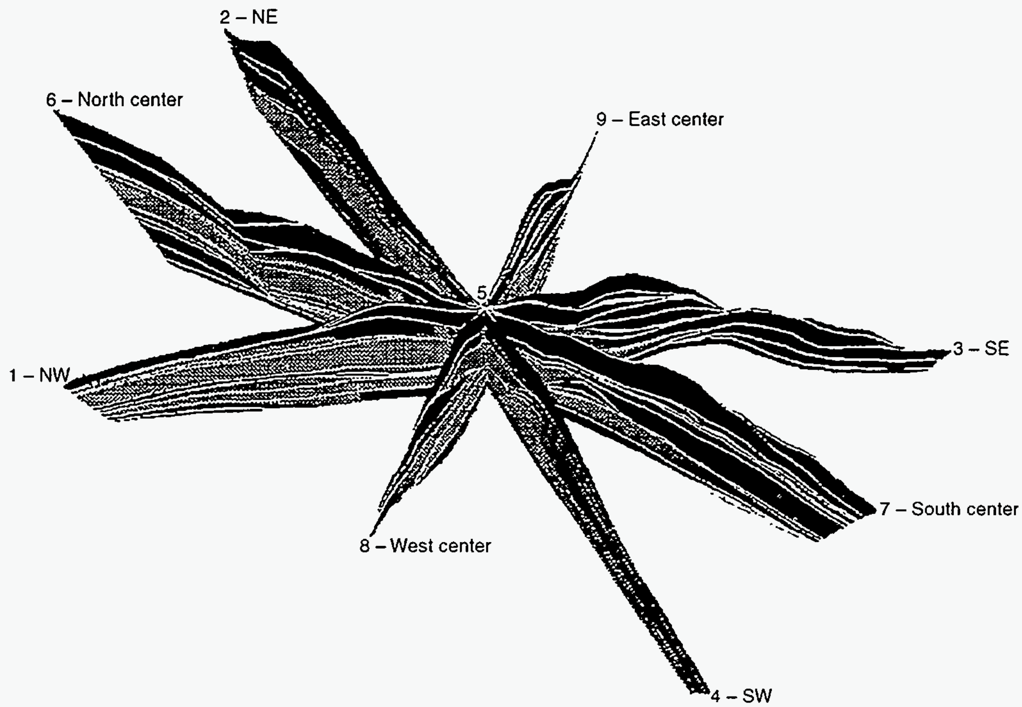


Fig. 5 Cross sections through central injector depict oil saturation (original oil is black) after injection of 0.82 PV for the case of no flow across channel boundaries. (Art reproduced from best available copy.)

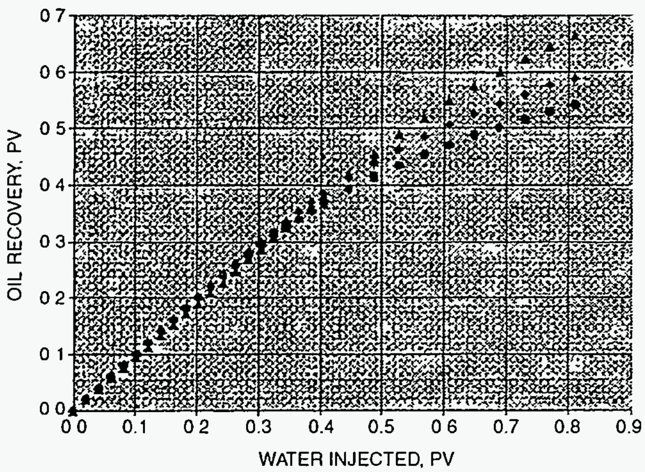


Fig. 6 Oil recovery as a function of water injected for three cases: five spot with unimpeded flow (◆), Z-direction transmissibility multipliers dependent on lithofacies (●), and line drive along channels with Z-direction transmissibility multiplier lithofacies (▲).

GEOSCIENCE/ENGINEERING CHARACTERIZATION OF THE INTERWELL ENVIRONMENT IN CARBONATE RESERVOIRS BASED ON OUTCROP ANALOGS, PERMIAN BASIN, WEST TEXAS AND NEW MEXICO

Contract No. DE-AC22-93BC14895

University of Texas at Austin
Bureau of Economic Geology
Austin, Tex.

Contract Date: Sept. 29, 1993
Anticipated Completion: Sept. 28, 1996
Government Award: $202,600

Principal Investigators:
F. J. Lucia
C. Kerans

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The primary objective of this project is to investigate styles of reservoir heterogeneity found in low-permeability pelleted wackestone–packstone facies and mixed carbonate–clastic facies found in Permian Basin reservoirs by studying similar facies exposed in the Guadalupe Mountains. Specific objectives for the outcrop study include construction of a stratigraphic framework, petrophysical quantification of the framework, and testing the outcrop reservoir model for effects of reservoir heterogeneity on production performance. Specific objectives for the subsurface study parallel objectives for the outcrop study.

Summary of Technical Progress

Subsurface Activities

Recovery of much of the South Cowden fields is only 20% of the original oil in place (OOIP). Perforations typically extend from near the top to only about halfway through the reservoir. The additional waterflood-displaceable oil that might be produced by adding deeper perforations was estimated with numerical simulation.

A three-dimensional (3-D) model was constructed for a 40-acre area in the northeast 160 acres of section 7 (Moss Unit tract 20). The petrophysical properties in the model are intended specifically to represent the tract 20 area. The well arrangement represents an injection pattern similar to that historically applied in the area: a line drive with two injectors on the west edge and three producers on the east. This well arrangement approximately matches the average number of injectors per section (eight) and the average injector/producer ratio (1:2) in sections 5, 6, 7, and 8.

Three approaches were tested for constructing the model: (1) smooth mapping of average properties in geologically defined high-frequency cycles, (2) two-dimensional (2-D) heterogeneous stochastic simulation of average properties in geologically defined high-frequency cycles, and (3) direct 3-D heterogeneous stochastic simulation. All the approaches were based on porosity, permeability, and initial water saturation data from well logs. Waterflood simulations with these models give similar results, but the direct 3-D stochastic simulations gave the best match to historical performance data (Fig. 1).

The incremental recovery was calculated by subtracting a base case matching the historical completion strategy from a case where all wells are deepened to penetrate the entire formation at the time of one displaceable hydrocarbon pore volume injection (Fig. 1). This time corresponds approximately to the present waterflood maturity in section 7. The predicted incremental recovery suggests that an additional 5% of the OOIP will be recovered in about 10 yr by adding well completions to the bottom of the formation (Fig. 2), or about 2 million bbl of incremental oil to be recovered from section 7. The time scale of the prediction was established by matching injectivity of the model to the average for sections 5, 6, 7, and 8.

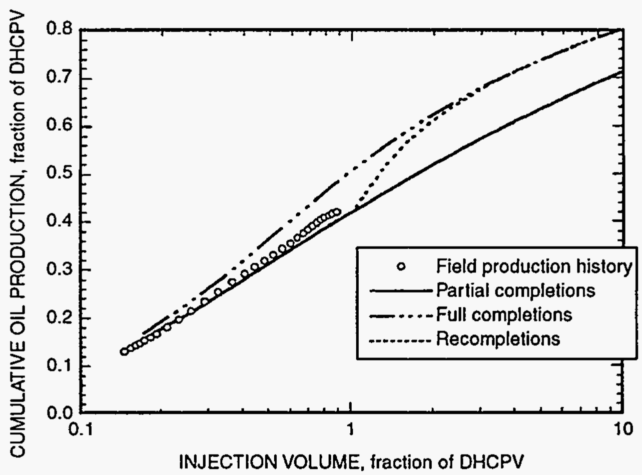


Fig. 1 Waterflood simulations using a stochastic simulation model compared with historical performance data for section 7 of the South Cowden field. Injection and production volumes are expressed as fractions of the displaceable hydrocarbon pore volume (DHCPV).

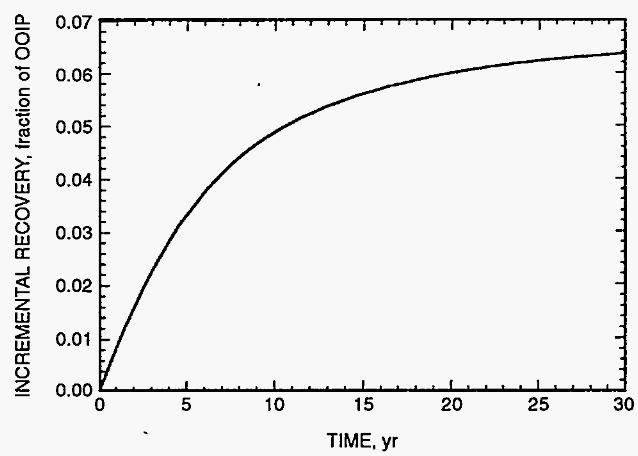


Fig. 2 Estimated additional recovery from recompleting South Cowden Moss Unit in the bottom half of the reservoir expressed as a fraction of the original oil in place (OOIP) (time zero is the date of recompletion).

RESERVOIR CHARACTERIZATION

VISUAL DISPLAY OF RESERVOIR PARAMETERS AFFECTING ENHANCED OIL RECOVERY

Contract No. DE-AC22-93BC14892

Michigan Technological University
Houghton, Mich.

Contract Date: Sept. 29, 1993
Anticipated Completion: Sept. 28, 1996
Government Award: $272,827

Principal Investigator:
James R. Wood

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this project is to provide the small- to medium-size oil-field operators with the tools necessary for an enhanced oil recovery (EOR) evaluation of the same quality and sophistication that only large international oil companies have been able to afford to date.

Summary of Technical Progress

Project Administration and Management

The Multimedia Database Management System has been completely transferred to the commercial software package Toolbook. There are many advantages to using commercially available software vs. a home-grown program to handle the data archiving and display needs. Documentation, tutorials, software support, and upgrade will all be taken care of by a commercial vendor and will relieve the project team of those responsibilities. Maps of the southern San Joaquin Valley oil fields and the Pioneer area are now in the database, as well as core photos, core data, thin section photomicrographs, and scanning electron microscope (SEM) photomicrographs.

Microsoft Access is the project's relational database management platform. All of the log data are stored in Access in LAS format. All other data are stored in Toolbook, in multimedia form, accessible via pulldown menus and a table of contents with hot links. Instructions for retrieving logs from the Access database are included in the Toolbook multimedia archive. Users can search the database by query and retrieve the logs from the main database table by well or by log type. Logs are then placed in smaller temporary Access tables from which they can be exported to applications programs.

Researchers here now have a log database that is independent of all the well-log evaluation programs (Crocker Petrolog, GeoGraphix QLA2, and TerraSciences TerraStation) but is capable of exporting data to any one of them.

A commercial database containing more than 77,000 geochemical analyses of brines recovered from wells throughout the United States was organized and imported into Microsoft Access. Analyses of samples from California wells are now easily retrievable for use in this project.

An academic license and three additional seats on GeoGraphix have been acquired. In February two more project staffers attended a training course at GeoGraphix's headquarters. With four Dongal keys to GeoGraphix, the program can be run at multiple sites, which will greatly enhance progress. A week was spent at Digital Petrophysics, Inc. (DPI) in Bakersfield in January loading log and formation-top data into GeoGraphix. Excellent maps of the Miocene unconformity (including all fault traces) were produced, and the maps were contoured to grid. Numerous cross sections were constructed through Pioneer Anticline, and currently structure contour maps of the tops of the Etchegoin and Monterey formations and the Reef Ridge sand and Reef Ridge shale members are being constructed.

Data Collection

During this quarter, several cross sections were completed through the Pioneer Anticline. Faults were correlated and mapped in a much more sophisticated fashion than previously, and fault-plane maps of all faults that cut the Miocene section in the Pioneer area were prepared. The tops of the following formations in all project wells were picked and forwarded to Michigan Technological University (MTU) in spreadsheet form: Etchegoin formation, Monterey formation, Reef Ridge sandstone, and Reef Ridge shale. Formation tops will be contoured using GeoGraphix. When overlain on the fault-plane maps, fault intersections can be determined and fault traces will be mapped on the formation-top contour maps. During the last quarter, a structure contour map of the top Miocene, with all fault traces displayed, was prepared in GeoGraphix.

The digitization, editing, and coloration of the surface geological maps of the southern San Joaquin Valley were completed. Additional maps and cross sections, including a geologic map and cross section of the Pioneer area recently acquired from Davis-Namson Associates, are being prepared.

All well-log calibration and analysis have, to date, been performed at DPI in the Crocker Data Processing Petrolog Program. Last quarter, construction of a Microsoft Access database to archive digitized log traces was completed. The logs are stored in LAS format and can be exported to any log evaluation or applications program. Thus independent operators can use the database as designed here to archive their log data, but are not constrained by it to use a specific applications package to evaluate their data. All of the Pioneer logs are now archived in the Access database.

A set of instructions which describes how to retrieve the logs from the Access database was placed in the Toolbook multimedia database management system. People searching for data in the Toolbook archive will encounter this instruction manual. It will describe how to locate the logs of interest, how the logs are formatted, and how to export logs from the database. Both the log database and the Toolbook multimedia database management system will eventually be written to CD ROM. Whereas documents, data tables, and graphics can be printed directly out of Toolbook, the digital log data must first be exported to an Access database to be used.

Digitization of all of the well logs that are being used to construct maps and three-dimensional (3-D) visualizations of the Miocene and Pliocene reservoirs on Pioneer Anticline is complete.

The conventional and sidewall core library of samples is now essentially complete. It consists of conventional cores and core analysis data from the Unocal McKittrick Front Nos. 415 and 418 wells in Cymric field and the Tenneco 62x-30 well in Pioneer field. Sidewall core and cuttings samples and core analysis data from the Gary Drilling, KLC 44, well No. 375x in Pioneer field are also in the sample library. Arco has divested its interests in the Pioneer area, so core from their wells may no longer be available, However, the cores and core data from the two McKittrick Front wells are so outstanding that acquiring data from additional wells is probably unnecessary.

It has been arranged for the core and core data from the two McKittrick Front wells to be released by Unocal to the California Well Sample Repository at California State University, Bakersfield, for the September 1996 Technology Transfer Workshop. They were shipped to the Repository in February and are now in storage there. Researchers here hope to arrange the eventual donation of the core and samples to the Repository, where they will reside in perpetuity and can be used as a resource by both industrial and research geologists.

A data set containing more than 77,000 geochemical analyses of brines recovered from wells throughout the United States was acquired from a commercial database vendor. A Microsoft Access database was designed, and the brine data were archived in it.

Data Analysis and Measurement

Petrophysics

Extensive petrophysical data sets were acquired from Unocal for the cores from the Unocal McKittrick Front Nos. 415 and 418 wells in Cymric field. A petrophysical data set for the Tenneco 62x-30 well in Pioneer field was acquired independently. Petrophysical data from the cores were used to calibrate the logs in these wells. The calibrations are being used to analyze existing logs and produce computed logs in uncored wells that penetrate the same stratigraphic intervals on the Pioneer Anticline.

Elemental analyses of 10 Pioneer samples were completed using the inductively coupled plasma spectrograph

(ICP) at MTU. Calibration of Fourier Transform Infrared (FTIR) spectroscopy standards is now complete. Twenty samples from Pioneer field were analyzed, but, because of contamination and instrumentation problems, will have to be rerun. During this quarter, error backgrounds on standards were run to help solve these problems. Computer reduction of the data is also being done.

Petrology

Arrangements have been made for staff at University of California Santa Barbara (UCSB) to continue the optical image analysis work. The Geology Department at UCSB has a state-of-the-art petrographic and image analysis laboratory. All electron photomicrographs and energy dispersive elemental (EDS) analyses were archived in the Toolbook multimedia database management system this quarter.

Optical petrographic analyses are complete for the 44 thin sections that have been prepared to date. Results include petrographic descriptions, 35mm slides, and 35mm prints of thin sections that are characteristic of each lithologic type. Additional work will be performed as necessary. All photomicrographs and thin section descriptions were archived in the Toolbook multimedia database management system this quarter.

An atlas of thin section petrology of representative reservoir samples from the southern San Joaquin Basin was acquired for the project. The 1988 atlas, which consists of several hundred described and interpreted photomicrographs from many fields, emphasizes diagenetic alteration. The photomicrographs and their captions were scanned into the Toolbook multimedia database management system, where they can be readily accessed on hard disk and eventually on CD ROM.

Log Calibration

Data preparation and log calibration were completed on the 13 wells in the nine-section Pioneer field area plus the two McKittrick Front wells.

Data preparation is complete for the 45+ wells in the original Pioneer Anticline study area plus five additional "regional" wells that were added to the data set to extend the picture of the anticline up-plunge to the west. Data from these wells have been entered into GeoGraphix. The additional 26 wells in the formation-tops spreadsheet are old wells that do not have usable borehole geophysical logs. The picks in these old wells were made from drillers' logs.

The tops of the Etchegoin formation, Monterey formation, Reef Ridge sand, and Reef Ridge shale in all project wells were picked, and fault-plane maps for all faults in the vicinity of Pioneer field were constructed. The data were forwarded to MTU, where maps are being constructed in GeoGraphix.

Preliminary model selection was completed for all 13 wells in the 9-section Pioneer area plus the 2 McKittrick Front wells. Results curves were generated for these wells. The results curves are calculated curves showing lithology, % clay, % shale, matrix type, porosity, and water saturation (S_w).

The wells are now undergoing final analysis using the program Symbiolog, developed by log analysts and programmers at DPI. Symbiolog uses a newly refined technique called multifacies zones summation analysis. Conventional log analysis packages apply one set of cutoffs (porosity, residual water saturation, etc.) to a unit. Multifacies zone summation analysis allows the user to define different facies within a reservoir and to assign a different cutoff value to each facies. Expected production within a heterogeneous reservoir can be estimated much more precisely than with the conventional approach.

Analysis of the wells with modern log suites is now complete. The model selection and analysis of the old electric-log-only wells that make up the bulk of the Pioneer Anticline log data set are being completed. This involves developing customized parameter tables for use in special algorithms that calculate lithology, % clay, % shale, matrix type, porosity, and S_w from this old electric-log data and plotting the results out in log form.

The new parameters and algorithms were recently tested on the two McKittrick Front wells with modern logs suites by running one set of calculated logs using all of the modern log and core data and a second set of calculated logs on the same intervals using only the spontaneous potential and one resistivity log. The output curves for the two runs were very similar, suggesting that output from the electric-log-only well runs will closely approximate the calculated curves that would be obtained if full modern log suites were available for all the wells.

When all the calculated curves are complete, they will be input to GeoGraphix, and maps and cross sections will be prepared showing the distribution of porosity zones, highly oil-saturated zones, and permeability barriers within the Monterey reservoir.

Modeling

The geochemical modeling program CHILLER is being used to model fluid–rock interaction. This has very practical significance because of active steamflooding of the Monterey and Etchegoin formations elsewhere in the southern San Joaquin Valley. Investigations of the feasibility of porosity prediction using CHILLER are continuing. Geochemical mass transfer work using CHILLER was continued.

Two thermodynamic databases are currently being used. SOLTHERM contains thermodynamic information on more than 400 fluid species, gases, and minerals. The data are valid over a temperature range of 0 to 300 °C. The database containing information on oxygen isotopes, OXYBASE, is complete.

Basin modeling work on fluid flow out of the deep San Joaquin Basin continued. This quarter, major strides were made in modeling the Monterey reservoir on Pioneer Anticline and producing 3-D surface and volume visualizations and pseudoseismic cross sections of the anticline using the program MatLab.

One-dimensional (1-D) basin modeling activities that use the program BasinMod have focused on analysis of the Elk Hills 934-29R well in the Naval Petroleum Reserve, the deepest well (24,442 ft) in the San Joaquin Valley. The well has excellent equilibrated downhole temperature profiles based on continuous temperature logging and a good vitrinite reflectance (Ro) profile that provide for calibration of the paleoheat flow. A generalized paleoheat flow model for the southern San Joaquin Basin is provided by model studies of lithospheric plate interactions that predict the thermal consequences of the complex plate interactions affecting the southern San Joaquin Valley. The results of the 1-D modeling study of Elk Hills 934-29R demonstrate that the downhole temperature profile observed in the well is not in equilibrium with observed Ro data.

The elevated temperature profile may be the result of episodic release of geothermal fluids. If correct, this interpretation suggests that all reservoirs shallower than approximately 17,000 ft are prospective. This is much deeper than any of the reservoirs presently being produced in the San Joaquin Valley, which are generally shallower than 10,000 ft.

A fluid inclusion study of vein carbonate samples taken from core recovered between 12,000 and 24,000 ft in the EH 934-29R well was completed. All of the samples contain petroleum fluid inclusions that range from light oil in the shallowest samples, through condensate in the intermediate samples, to wet gas in the deepest sample, providing evidence that hydrocarbon migration has occurred throughout this deep section.

2-D and 3-D Field Visualizations and Basin Models

The 3-D visualizations of the Pioneer Anticline are being constructed in MatLab. This commercially available statistics and visualization package is both flexible and powerful and can easily perform both 3-D surface and 3-D volume visualizations. The top Miocene and fault-trace data were loaded into MatLab and produced an excellent 3-D surface visualization, which accurately portrayed all of the fault discontinuities (Fig. 1). Surface visualizations are being constructed in 3-D for the other formation tops recently acquired from DPI, and the mapped fault planes will soon be added so that accurate fault intersections can be displayed on all formation tops and fault planes can be displayed with true dip angles. Cross sections can be made through the anticline at any desired angle.

MatLab is being used to produce pseudoseismic sections from spontaneous potential (SP) and gamma-ray logs. With the program developed, individual pseudoseismic logs (log traces whose amplitudes have been color-coded to resemble

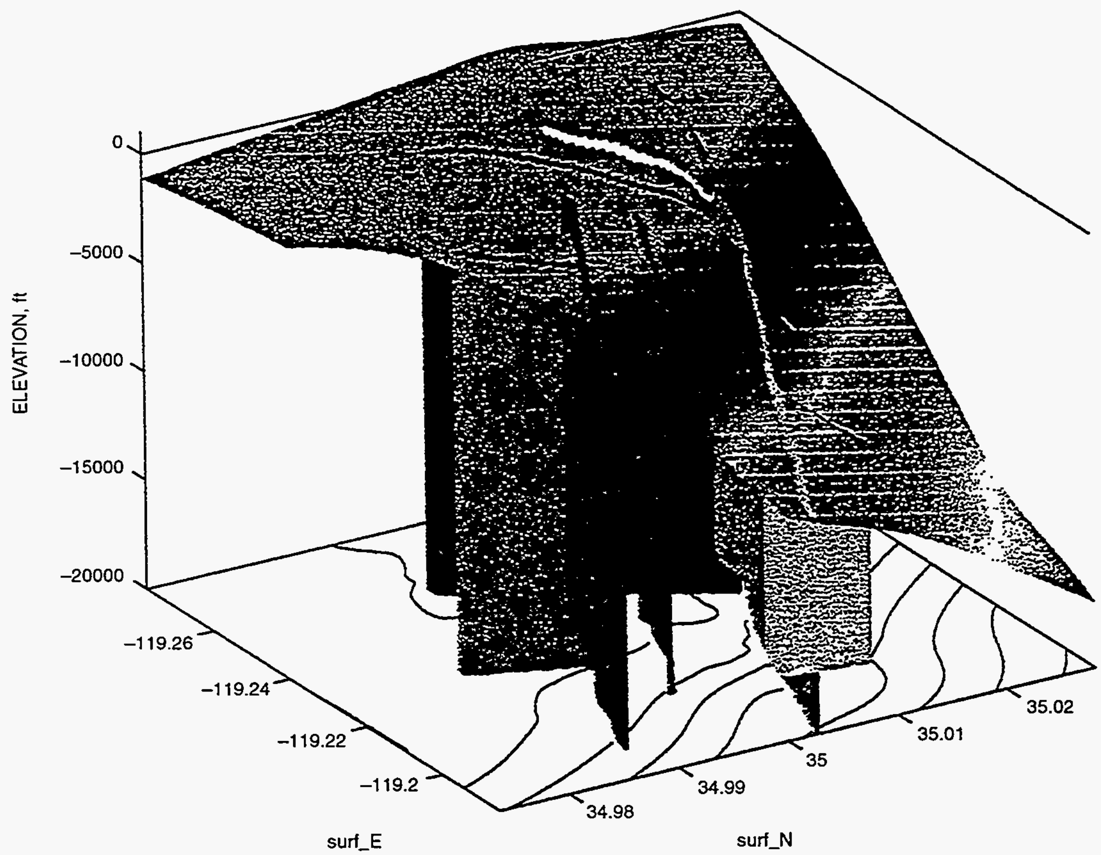


Fig. 1 Structure contour map on the top Miocene, Pioneer field area, displayed as a three-dimensional surface visualization in MatLab. Fault intersections with the top Miocene surface are currently displayed in their proper declinations as vertical planes but will soon be displayed at their true inclinations as well. (Art reproduced from best available copy.)

seismic amplitude traces) can easily be selected from a map-view window and then displayed as well-log or pseudoseismic cross sections. This capability adds another useful dimension to the project's visualization capabilities.

Akcess.basin 2-D, 3-D modeling software was acquired and installed on the Sun Workstation in the Subsurface Laboratory at MTU. This software uses a finite-element formulation to examine the effects of thermal processes (conduction, convection, advection), fluid-flow processes (compaction-driven, hydraulic-head driven), sealing mechanisms, and sedimentation/erosion during the development of a sedimentary basin. The program also predicts hydrocarbon generation (timing, location, and rate) and migration patterns. Modeling of the southern San Joaquin Valley will commence soon.

Technology Transfer

A paper on the BasinMod study of the deepest well in the San Joaquin Valley is being prepared for publication.

FIELD DEMONSTRATION IN HIGH-PRIORITY RESERVOIR CLASSES

WEST HACKBERRY TERTIARY PROJECT

Contract No. DE-FC22-93BC14963

Amoco Production Company
Houston, Tex.

Contract Date: Sept. 3, 1993
Anticipated Completion: Apr. 2, 1997
Government Award: $6,017,500

Principal Investigators:
Travis Gillham
Bruce Cerveny
Ed Turek

Program Manager:
Edith Allison
Bartlesville Project Office

***Reporting Period:* Jan. 1–Mar. 31, 1996**

Objective

The objective of this project is to demonstrate the technical and economic feasibility of combining air injection with the double displacement process (DDP) for tertiary oil recovery. The DDP is the gas displacement of a water-invaded oil column for the recovery of oil through gravity drainage. The novel aspect of this project is the use of air as the injection fluid. The target reservoir for the project is the Camerina C-1,2,3 sand located on the west flank of West Hackberry field in Cameron Parish, La. If successful, this project will demonstrate that the use of air injection in the DDP can economically recover oil in reservoirs where tertiary oil recovery is uneconomic.

Summary of Technical Progress

The first quarter of 1996 was outstanding both in terms of volume of air injected and low-cost operations. More air was injected during this quarter than in any preceding quarter. The run time of the compressors improved and repairs were minimal. Operating costs were low because no repairs were required for injection or production wells.

Injection and Production Wells

In fault block IV, the Gulf Land D No. 51, the most upstructure well, serves as the air injector. The Gulf Land D No. 44 and No. 45 wells are the next highest wells completed on structure and are expected to show the earliest production response. The location of each well in fault block IV is shown in Fig. 1.

The updated reservoir model suggests that, if all available air injection capacity [4 million standard cubic feet per day

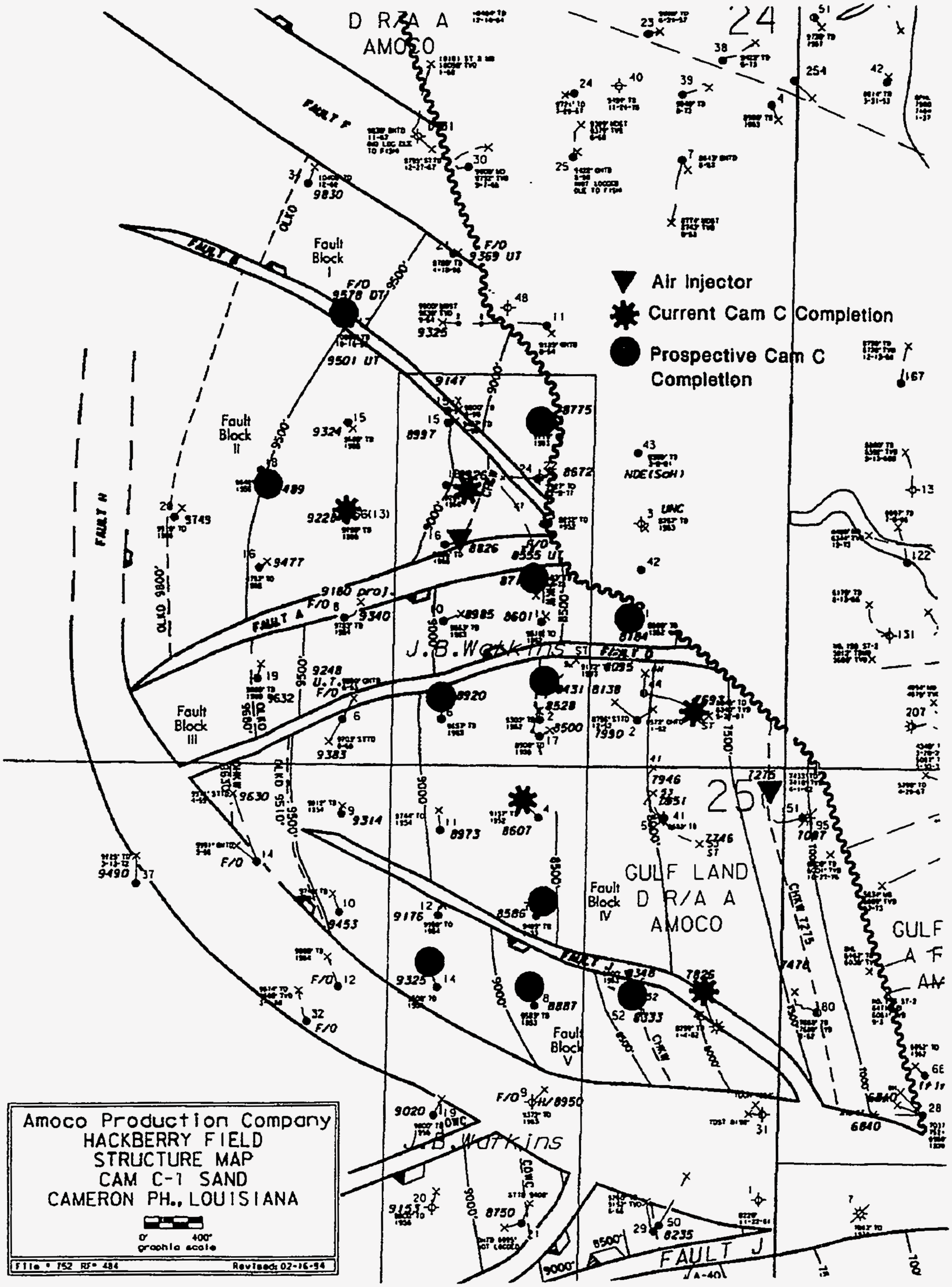


Fig. 1 Structure map for the Cam C-1 sand, West Hackberry field, Cameron Parish, La. (Art reproduced from best available copy.)

(MMSCFD)] is injected into the Gulf Land D No. 51, production response will be seen in the Gulf Land D No. 44 by mid-1996 and in the Gulf Land D No. 45 during the first quarter of 1997. To ensure initial production response during 1996, the operating strategy was modified from injection into both fault blocks simultaneously to injection of all available air injection capacity into one fault block. All available air injection capacity is allocated for injection into the Gulf Land D No. 51 in fault block IV. If at any time the Gulf Land D No. 51 is unable to accept the entire injection stream, the remainder will be injected into the Watkins No. 18 in fault block II.

As noted in the previous quarterly report, lower injectivity in the Gulf Land D No. 51 during December 1995 was expected because of an additional workover to clean out the well. An experiment involving the injection of 2% potassium chloride (KCl) water into the Gulf Land D No. 51 successfully enhanced injectivity such that the well accepted the full 4 MMSCFD of air injection capacity throughout the first quarter of 1996. The source for the KCl water was the currently inactive purge water system. Although the injection of KCl water into the Gulf Land D No. 51 improved air injectivity on several occasions, the reason for this is unclear.

On Oct. 8, 1995, the Gulf Land D No. 44 was recompleted to the Cam C-1,2 sand and tested gas lifting at a rate of 0 thousand standard cubic feet of gas per day (MSCFGD) plus 0 bbl of oil per day (BOPD) and 413 bbl of water per day (BWPD). The Gulf Land D No. 44 is the next most upstructure well in fault block IV after the Gulf Land D No. 51 and is expected to show the earliest production response in fault block IV. The Gulf Land D No. 44 is production tested once each week and then shut in. Thus far the Gulf Land D No. 44 has continued to show no evidence of oil, gas, or nitrogen production. Although an oil bank has not arrived, air injection has raised reservoir pressure sufficiently to increase test rates for the Gulf Land D No. 44 from 413 to more than 700 BWPD.

The Gulf Land D No. 45, which had watered out in December 1990, is located slightly downstructure to the Gulf Land D No. 44. On Aug. 17, 1995, the No. 45 was recompleted in the Cam C-1,2 sand in the identical completion interval as before and tested at a rate of 190 BOPD, 451 BWPD, and 25 MSCFGD while on gas lift. After 1 month, production from the well had declined to 60 BOPD and 480 BWPD. If air injection was the source of the oil production in the Gulf Land D No. 45, the oil cut should have increased when air injection was restarted in October 1995. As indicated in Table 1, the oil cut has continued to decrease since the initial production in August 1995.

From August 1995 through March 1996, the Gulf Land D No. 45 produced 12,101 bbl of oil. In light of the increasing water cut in the well, the source of the new oil production is believed to be a thin interval producing through a gravel pack that had sanded up in the previous Cam C-1,2 completion. Oil production as a result of the air injection project is expected to occur in the Gulf Land D No. 45 after production response is noted in the Gulf Land D No. 44.

TABLE 1

Gulf Land D No. 45 Production

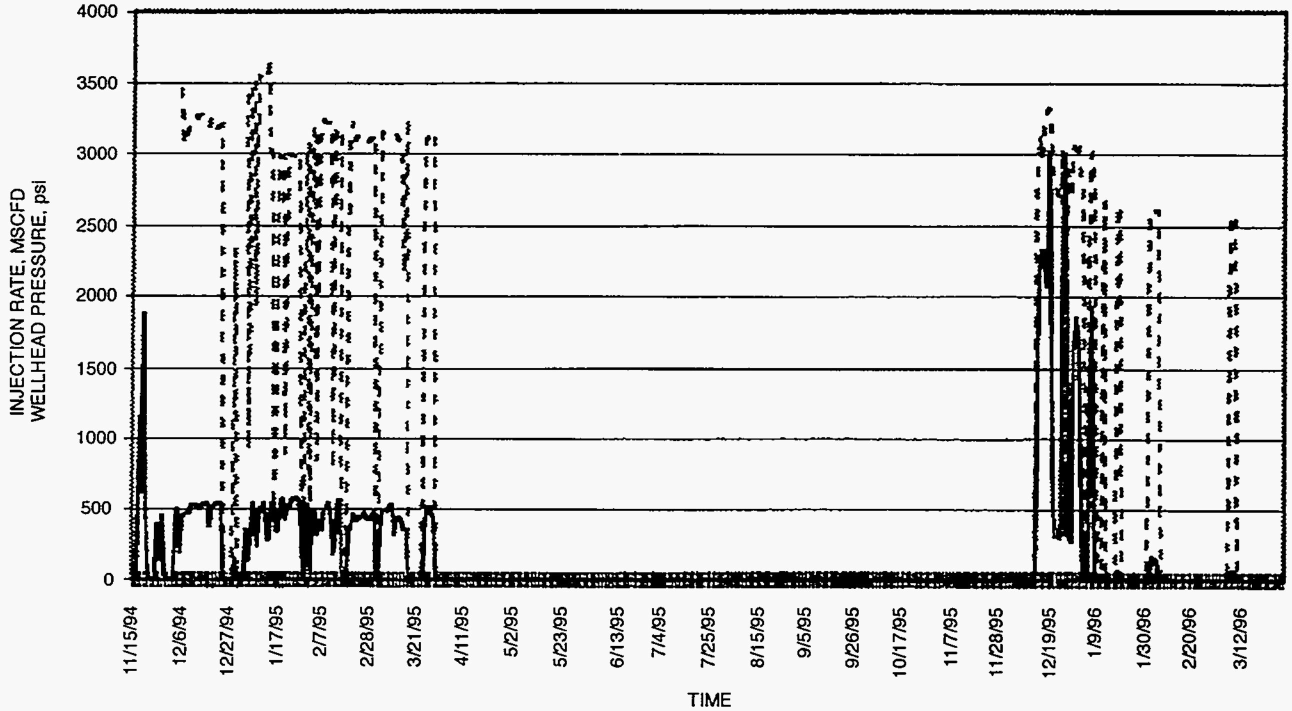
Month	Oil, bbl/d	Water, bbl/d	Percent water	Gas, MSCFD
		1995		
August	183	415	69	72
September	60	480	89	89
October	55	480	90	80
November	50	450	90	50
December	45	450	91	40
		1996		
January	*Shut in*			
February	31	378	92	21
March	40	461	92	4

Air Compressor Operations

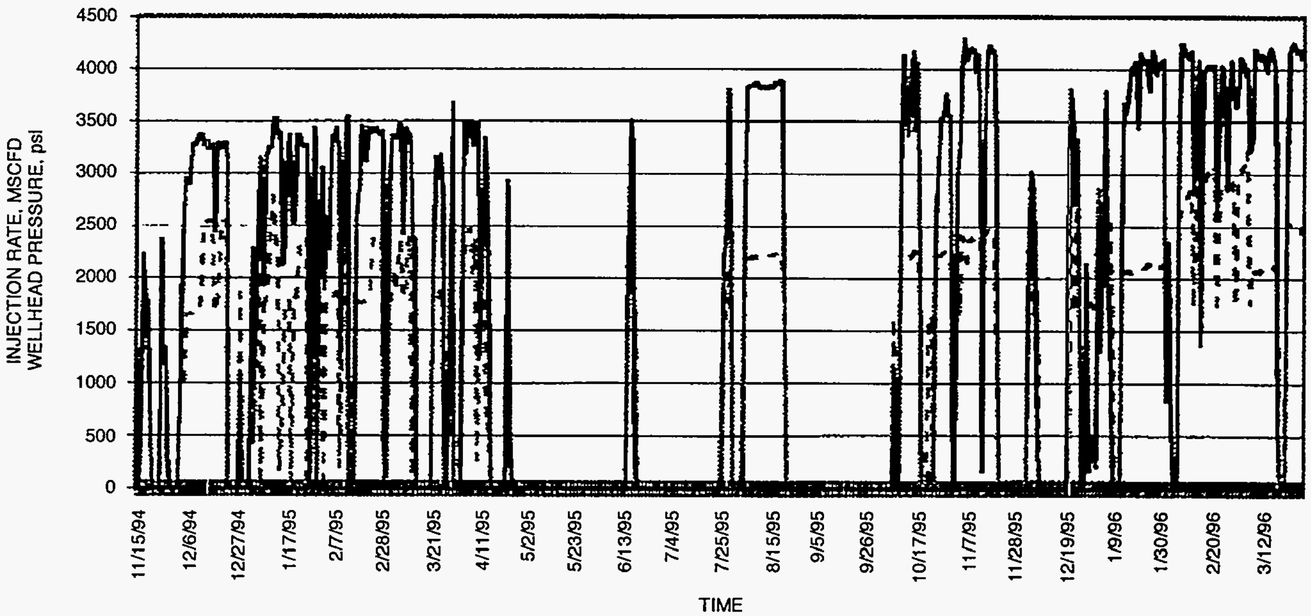
An improvement in air compressor run time resulted in a significant increase in the amount of air injected this quarter. Between project start-up on Nov. 17, 1994, and Dec. 31, 1995, 634 MMSCF of air was injected for an average rate of 1.5 MMSCFD and an effective run time of 39%. A plot of air injection rates and pressures is included as Fig. 2. Although some problems occurred with the air injection wells, problems within the air injection surface facilities, mainly the air compressors, were the major cause of downtime. Equipment and operating procedures were modified throughout 1995 to improve run-time performance. As a result, air injection operating performance improved significantly during the first quarter of 1996. The average compressor run time and the average daily injection rate have doubled. Air injected this quarter alone accounts for 31% of the total air injected since project start-up. A plot of cumulative air injected vs. time is included as Fig. 3. Table 2 compares the performance for the first quarter of 1996 with the performance for the first 13.5 months of the project.

Some downtime occurred this quarter, but no major failures or repairs occurred. Downtime this quarter was due to scheduled preventive maintenance and inspection, replacement of the reciprocating compressor fifth-stage rings and rider band caused by plugging of the lubricating pump with debris from the synthetic lubricant temporary day tank, and a screw compressor balancing piston control line break caused by vibration.

Periodic inspections of the reciprocating compressor have shown that the Mobil Rarus 829 synthetic lubricant is providing adequate lubrication and that the lubricant rate can be reduced. In mid-February, the synthetic lubricant rate was reduced from 5.0 to 3.4 gal/d to reduce both operating cost and the potential for deposits in the compressor piping. Next quarter, a change back to the original bulk synthetic system will be made with the use of Mobil Rarus 829, and the temporary day tank will be eliminated.



(a)



(b)

Fig. 2 Plot of air injection rates (———) and wellhead pressures (- - - - -) for (a) Watkins No. 16 (11/94 to 3/95) and No. 18 (12/95 to 3/96) wells and (b) Gulf Land D No. 51 well.

Updated Bottomhole Pressure Data

A minimum of three bottomhole pressure surveys are taken every quarter to assess the effect of air injection on reservoir pressure. The most recent series of bottomhole pressure surveys was taken during March 1996. Table 3 demonstrates the impact of air injection on reservoir pressure.

Figure 4 is a plot of bottomhole pressure vs. time. As noted in Fig. 4 and Table 3, reservoir pressure has risen significantly in fault blocks IV and V as a result of air injection. This increase confirms that the project is

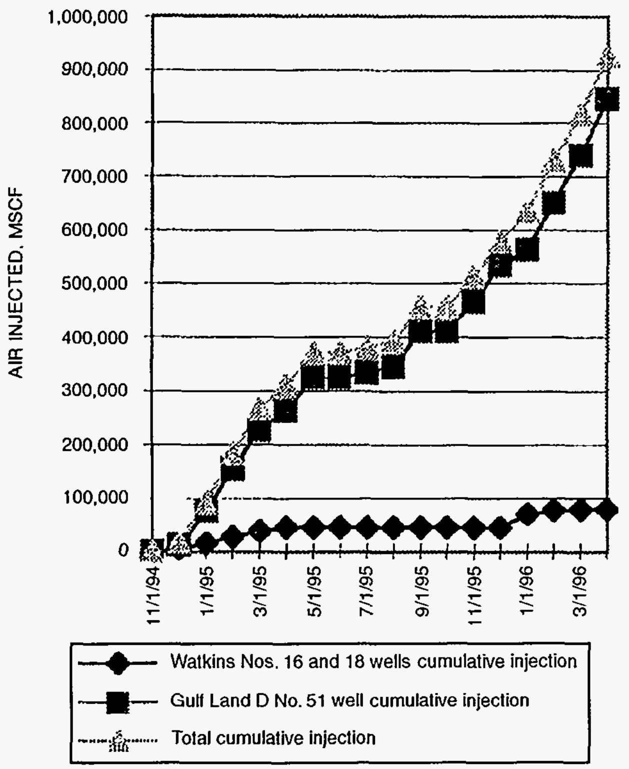


Fig. 3 **Plot of cumulative air injected vs. time, West Hackberry Tertiary Project.**

TABLE 2

Air Injection Operating Performance

	11/17/94 to 12/31/95	1/1/96 to 3/31/96
Total air injected, MMSCF	634	293
Average compressor run time, %	39	80
Average injection rate, MMSCFD	1.5	3.2

influencing the intended reservoir volume and that the current geologic interpretation is correct.

Technology Transfer Activities

During January, Amoco personnel submitted for Society of Petroleum Engineers' (SPE) review a paper entitled "The Economics of Light Oil Air Injection Projects" which will be presented at the SPE/DOE Improved Oil Recovery Conference in Tulsa, Okla., on Apr. 21–24, 1996. A discussion of the economics of the West Hackberry Tertiary Project was included in the paper.

An Amoco research engineer stationed in Tulsa, Okla., provides technical and reservoir modeling support for the West Hackberry Tertiary Project. On Feb. 14, 1996, a talk on the Hackberry project was presented to the Oil Industry Outreach Conference in Houston, Tex. The attendees included oil industry representatives and representatives from a broad cross section of national laboratories and other nontraditional technology suppliers.

On Feb. 21, 1996, the Amoco research engineer gave another presentation on Hackberry entitled "Monitoring West Hackberry Field Performance Under Air Injection" to the 4D—Time Lapse Reservoir Monitoring and Characterization Workshop sponsored by Energy Research Clearing House in Houston, Tex. Approximately 80 individuals representing a mix of exploration and production disciplines and organizations attended this workshop, which was organized to identify time-lapse fluid-imaging technology needs and to plan a new joint industry fluid-imaging project. An online version of this presentation has been placed on a Society of Petroleum Engineers' Internet file server for easy access by the public. This presentation can be accessed at **www.neosoft.com/pub/users/s/spe**.

To further publicize the project, Amoco, Louisiana State University, and DOE personnel contributed comments to an article discussing the West Hackberry Tertiary Project which appeared in the February 1996 *Hart's Oil and Gas World*. Amoco personnel are preparing a West Hackberry article for *Oil and Gas Journal*.

TABLE 3

Impact of Air Injection on Reservoir Pressure

Fault block	Cumulative air injected (to Mar. 31, 1996), MMSCF	Well	Completion interval	Reservoir pressure (at –9000 ft subsea), psi: Before injection (May–August 1994)	Most recent (March 1996)	Pressure increase
II	79	GLD 56	Cam C-1,2,3	3301	3320	19
IV and V	848	GLD 45	Cam C-1,2	—	2967	—
		GLD 52	Cam C-1,2	2675	3009	334
		Watkins 4	Cam C-3	2470	2738	268

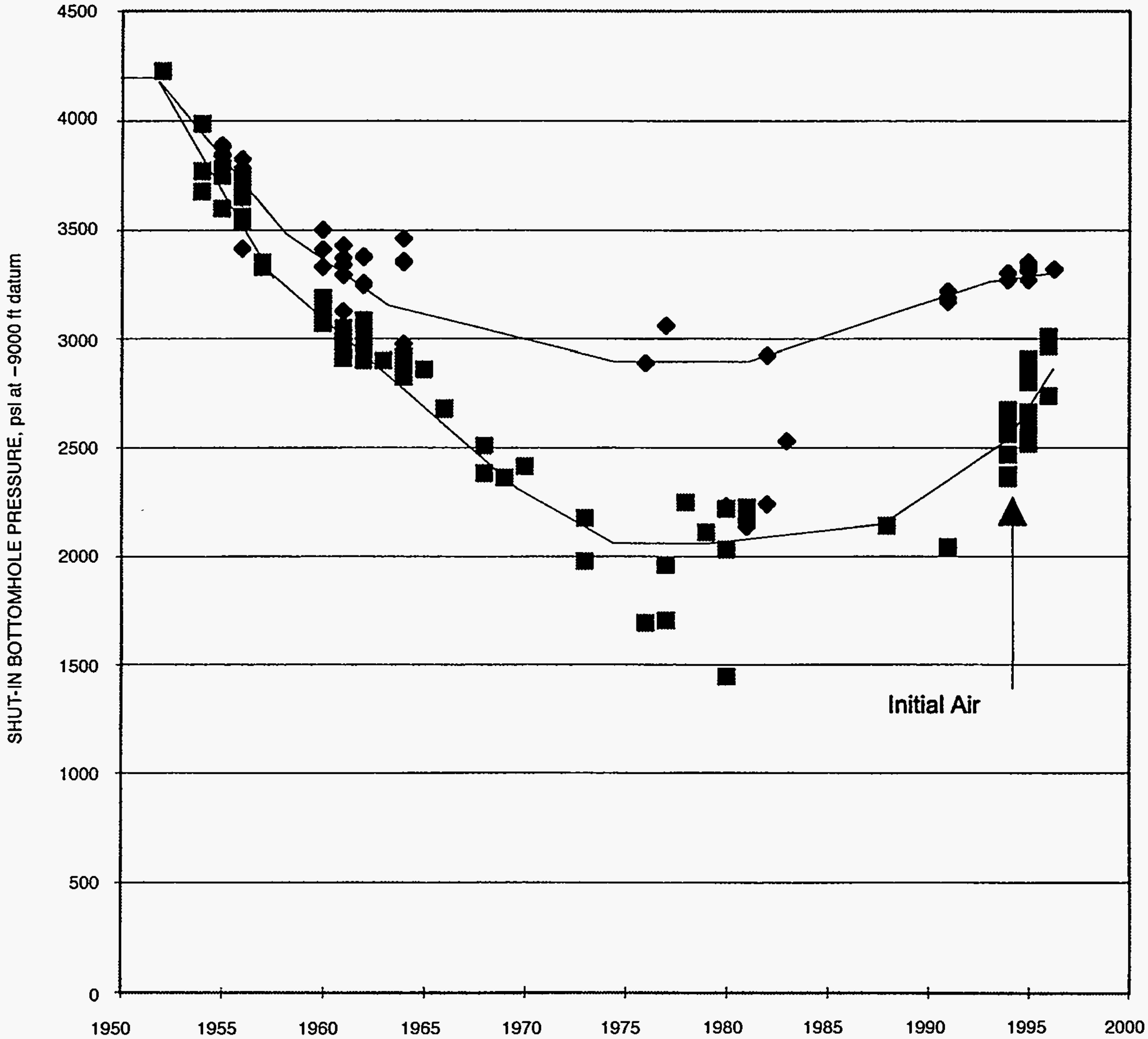


Fig. 4 Plot of bottomhole pressure vs. time, West Hackberry air injection project. ◆, fault blocks I and II. ■, fault blocks III, IV, and V.

INCREASED OIL PRODUCTION AND RESERVES FROM IMPROVED COMPLETION TECHNIQUES IN THE BLUEBELL FIELD, UINTA BASIN, UTAH

Contract No. DE-FC22-93BC14953

Utah Geological Survey
Salt Lake City, Utah

Contract Date: Sept. 30, 1993
Anticipated Completion: Sept. 30, 1998
Government Award: $228,653

Principal Investigator:
M. Lee Allison

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this project is to increase oil production and reserves in the Uinta Basin by demonstration of improved completion techniques. Low productivity is attributed to gross production intervals of several thousand feet that contain perforated thief zones, water-bearing zones, and unperforated oil-bearing intervals. Geologic and engineering characterization and computer simulation of the Green River and Wasatch formations in the Bluebell field will determine reservoir heterogeneities related to fractures and depositional trends. This will be followed by drilling and recompletion of several wells to demonstrate improved completion techniques based on the reservoir characterization. Technology transfer of the project results will be an ongoing component of the project.

Summary of Technical Progress

Comprehensive Fractured-Reservoir Model

Data (net pay thickness, porosity, and water saturation) of more than 100 individual beds in the lower Green River and Wasatch formations were used to generate geostatistical realizations (numerical representations) of the reservoir properties. The data set was derived from the Michelle Ute and Malnar Pike demonstration wells and 22 other wells in a 20-square-mile (52-km^2) area. Beds were studied independently of each other. Principles of sequential Gaussian simulations (SGS) were used to generate geostatistical realizations of the beds. The steps involved in generating the realizations were

- Data were transformed to normally distributed data.
- Two-dimensional horizontal variogram was calculated from the transformed data.
- Model was obtained for the variogram.
- Parameters of the variogram model were used in the SGS algorithm to generate thickness, porosity, and water-saturation distributions.
- Output of the SGS algorithm was converted back to follow the original data distributions.

Figures 1 to 3 show one realization of thickness, porosity, and water saturation, respectively, in zone 5 (beds 24 to 41, lower Wasatch) in the 20-square-mile (52-km^2) area. Realizations will be generated for all beds in the lower Wasatch formation (beds 13 to 41). The realizations for all beds will be combined to generate a reservoir image, which will be used in the reservoir numerical-simulation flow model.

Regulatory Issues

The Utah Geological Survey (UGS) director and energy section chief were invited to meet with county commissioners from every oil-producing county in the State, representatives from the State Tax Commission, and Utah Association of Counties to discuss state tax incentives for enhanced-oil-recovery (EOR) and horizontal-drilling projects in Utah. The UGS used U.S. Department of Energy (DOE)-sponsored Bluebell and Monument Butte fields (both Class I) and Paradox Basin (Class II) as examples of the economical potential of EOR and horizontal drilling to explain the technical aspects of such activities.

Personnel from the UGS also met with the Utah Department of Natural Resources executive director and representatives of the Utah Office of Energy and Resource Planning. As a result of the meeting, the Department changed its official opposition to a state legislative bill that provides tax incentives for EOR and horizontal-drilling projects.

The UGS is preparing a white paper in cooperation with the Utah Office of Energy and Resource Planning outlining a state strategic initiative to increase oil production in Utah. The strategy will focus on the expansion of government–industry partnerships similar to those established in the Bluebell and Paradox projects and modification of tax philosophies and regulatory processes to take into account varying reservoir conditions.

Technology Transfer

Two masters' theses were completed.[1,2]

The UGS has established a home page on the Internet. The address is **http://utstdpwww.state.ut.us/~ugs/**. The site includes a page describing the UGS/DOE cooperative studies (Bluebell, Paradox, and Ferron) and a separate Bluebell page.

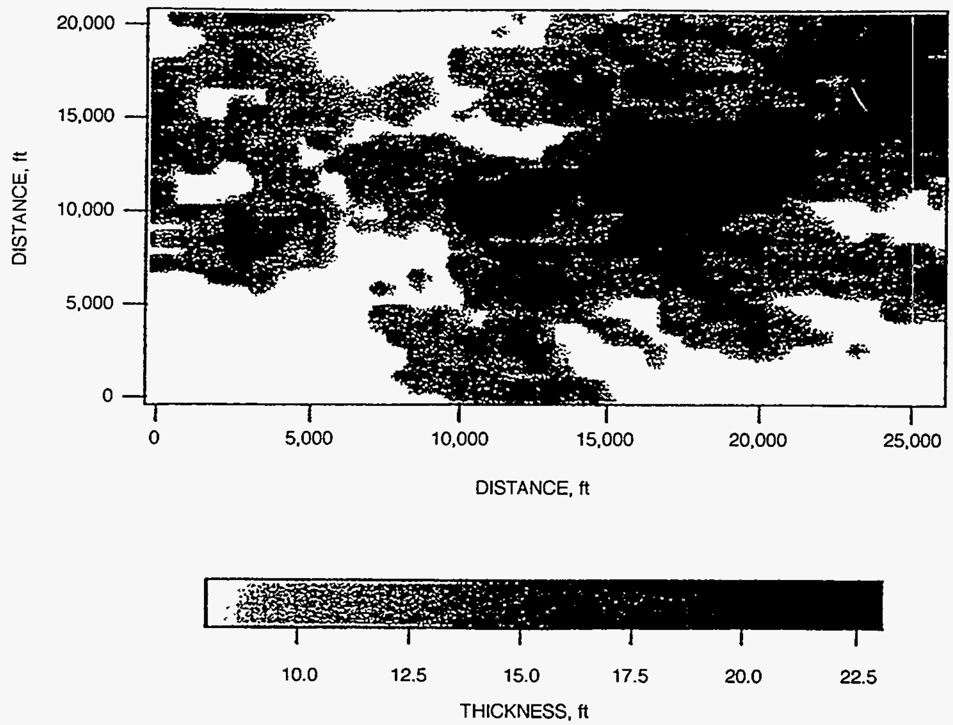


Fig. 1 Thickness distribution in zone 5. (Art reproduced from best available copy.)

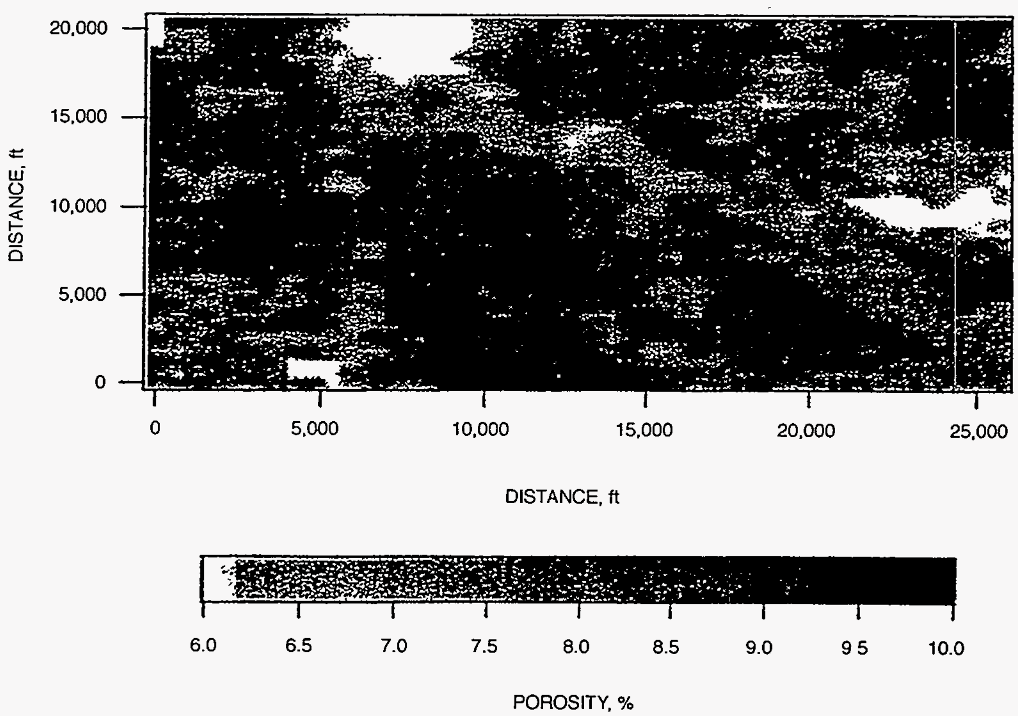


Fig. 2 Porosity distribution in zone 5. (Art reproduced from best available copy.)

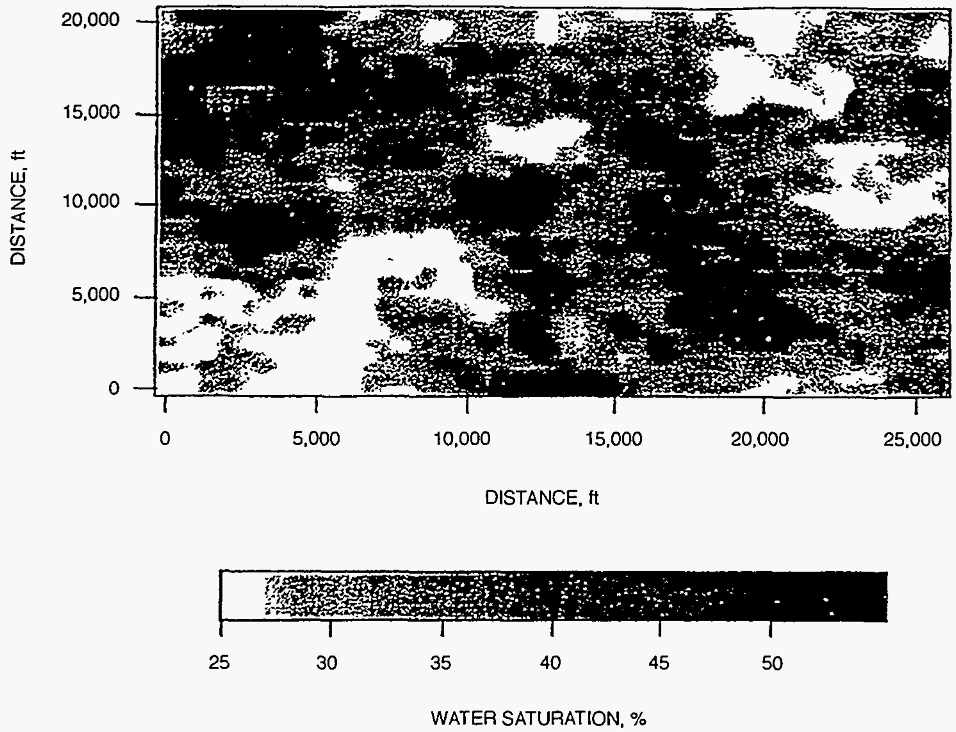


Fig. 3 Water saturation distribution in zone 5. (Art reproduced from best available copy.)

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2. Mary Beth Wegner, *Core Analysis and Description As an Aid to Hydrocarbon Production Enhancement—Lower Green River and Wasatch Formations, Bluebell Field, Uinta Basin, Utah,* Master's Thesis, Brigham Young University, Provo, Utah, 1996.

APPLICATION OF ADVANCED RESERVOIR CHARACTERIZATION, SIMULATION, AND PRODUCTION OPTIMIZATION STRATEGIES TO MAXIMIZE RECOVERY IN SLOPE AND BASIN CLASTIC RESERVOIRS, WEST TEXAS (DELAWARE BASIN)

Contract No. DE-FC22-95BC14936

University of Texas at Austin
Austin, Tex.

Contract Date: Mar. 31, 1995
Anticipated Completion: Mar. 30, 1997
Government Award: $1,010,208

Principal Investigator:
Shirley P. Dutton

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The primary objective of this project is to demonstrate that detailed reservoir characterization of slope and basin clastic reservoirs in sandstones of the Delaware Mountain Group in the Delaware Basin of West Texas and New Mexico is a cost-effective way to recover a higher percentage of the original oil in place through strategic placement of infill wells and geologically based field development. Project objectives are divided into two major phases. The objectives of the reservoir characterization phase of the project are to provide a detailed understanding of the architecture and heterogeneity of two fields, the Ford Geraldine Unit (FGU) and Ford West field, which produce from the Bell Canyon and Cherry Canyon formations, respectively, of the Delaware Mountain Group, and to compare Bell Canyon and Cherry Canyon reservoirs. For reservoir characterization, three-dimensional (3-D) seismic data, high-resolution sequence stratigraphy, subsurface field studies, outcrop characterization, and other techniques will be used. Once the reservoir-characterization study of both fields is complete, a pilot area of approximately 1 square mile in one of the fields will be chosen for reservoir simulation. The objectives of the implementation phase of the project are to (1) apply the knowledge gained from reservoir characterization and simulation studies to increase recovery from the pilot area, (2) demonstrate that economically significant unrecovered oil remains in geologically resolvable untapped compartments, and (3) test the accuracy of reservoir characterization and flow simulation as predictive tools in resource preservation of mature fields. A geologically designed, enhanced-recovery program [carbon dioxide (CO_2) flood, waterflood, or polymer flood] and a well-completion program will be developed, and one to three infill wells will be drilled and cored. Through technology transfer workshops and other presentations, the knowledge gained in the comparative study of these two fields can then be applied to increase production from the more than 100 other Delaware Mountain Group reservoirs.

Summary of Technical Progress

Geophysical Characterization

The data were loaded and quality checked on the Landmark workstation. Preliminary attempts at generating synthetics with wells in the survey were made. Synthetic generation of wells from the Ford West field (Cherry Canyon) were created, and attempts were made to tie the synthetics with the seismic. The results were somewhat disappointing because of the lack of complete sonic logs. The majority of the well logs in the area that have sonic and/or density logs were not logged throughout the entire section. Attempts will continue, and preliminary plans to run a vertical seismic profile (VSP) are being investigated.

Coherence Technology Company processed the 3-D volume in March 1996. The high signal-to-noise ratio of the data allowed the processors to use three different processing strings to get three different "looks" from the data. The coherence "cube" (coherency processing) is expected to help with the stratigraphic interpretation of the survey.

Reservoir Characterization

Subsurface Field Studies

Cores from 85 wells are now available for detailed geologic, petrographic, and petrophysical description. These 85 cores include 27 that were studied by Ruggiero[2] and 58 additional cores that were shipped from Conoco to the Bureau's Core Research Center this quarter. Core-analysis data from 171 wells were entered into a computer database this quarter.

The gamma-ray logs in Geraldine Ford field were run in the 1950s and 1960s by many different companies at different scales and sensitivities and therefore cannot be directly compared. During this quarter all the gamma-ray logs were normalized to API units using modern logs from the field to develop normalization equations in the following form: API units = m (old units) + b, where the slope and y-intercept were calculated for each log individually.

Tops for the reservoir sandstones and adjacent nonreservoir interval have been picked on all logs in Geraldine Ford field. The log curves, elevation datum, total depth, latitude and longitude, and tops for each well have been entered into the Landmark software OpenWorks™. The subsurface log and core data are being used to address reservoir heterogeneity caused by depositional processes or postdepositional diagenesis.

A major focus this quarter was a reconnaissance examination of the petrophysical characteristics of the Ramsey sandstones, including (1) examination of the cements and pore structure of about 20 samples of representative rocks from the Ramsey sandstone 1A, 1B, and 2 units in the FGU 60 core with scanning electron microscope (SEM) imaging, and (2) examination of porosity and permeability relationships with the use of the results of nearly 8000 core analyses from throughout the FGU.

SEM examination, supplemented by qualitative compositional analysis with the energy dispersive system (EDS), identified the major components in the Ramsey sandstones. Quartz, orthoclase, and plagioclase are the dominant framework grains. Diagenetic phases include abundant authigenic clay throughout the Ramsey sandstones, locally abundant calcite cement, pervasive but volumetrically minor authigenic quartz overgrowths, and local anhydrite. The appearance and qualitative composition of the authigenic clay is similar to authigenic chlorite identified elsewhere in the Bell Canyon formation by Williamson.[2] Partial dissolution of plagioclase grains and replacement of grains by albite are fairly abundant. In the description of representative chips, SEM failed to identify any prominent vertical trends within the Ramsey sandstone units in the FGU 60 core. The framework grain composition and diagenetic history of the Ramsey sandstone in this field is similar to that described for other Bell Canyon sandstones.[2-4]

The porosity and permeability data were subdivided and evaluated by stratigraphic unit and examined vertically through the unit and in cross plots. The Ramsey 1A, 1B, 1C, and 2 sandstone units have remarkably similar permeability characteristics, with distributions skewed from the expected log normal distribution and modal values of about $10^{1.5}$ mD. The skewed distribution is tentatively interpreted as the result of combining more than one population with different permeability characteristics. Permeability varies systematically with position in each Ramsey sandstone unit, with highest values as well as the highest average permeability at the top of each unit and lowest average immediately below. Some of the samples at the top of the unit have slightly higher permeability relative to porosity on a porosity vs. permeability cross plot, which might indicate permeability enhancement as a result of leaching. The low values may correspond to calcite cementation commonly observed near the top of some units. Better constraint on the petrographic characteristics of samples with these permeability distributions are needed for further interpretation of these data.

Outcrop Characterization

Northeast-trending grabens formed during Late Pennsylvanian deformation and influenced sediment dispersal patterns both on the shelf and in the northern Permian Basin. The possibility of structural controls on the exceptionally straight, narrow, parallel channels in which Delaware sands were deposited, according to Williamson[2] and Linn,[5] is being investigated. The northeasterly grabens observed at the surface now formed during Miocene and later extension, explain Budnik[6] and Hentz and Henry.[7] Miocene graben widths are similar to widths of Delaware sand channels mapped in the West Geraldine and West Ford field areas. [5] Where earlier-formed grabens have been reactivated, fracture-enhanced permeability in Delaware sands may be greater. To test that concept, data on fracture orientations and spacing from aerial photos and from outcrop will be compiled.

Producibility Problem Characterization

Review of the waterflood history of FGU continued this quarter, and review of the CO_2 flood history began. All production data have been assembled as part of the production data file. FGU was waterflooded from 1969 to 1981, and CO_2 flooding started in 1981. Increased secondary production was less than predicted by computer models, possibly because the models did not include permeability barriers parallel to bedding, which subdivide the reservoir.[1] Of the 6.8 million bbl of oil produced through January 1981, 3.5 million were attributed to the waterflood. The high initial water saturation, combined with fair primary performance, resulted in a poor secondary recovery of only about 4.5% original oil in place.[8]

Injection of CO_2 began in February 1981, when the oil production rate from the waterflood had declined to 300 bbl/d. The miscible flood is a continuous-slug CO_2 injection process.[8] The CO_2 flood increased oil production to more than 1700 bbl/d once a consistent supply of CO_2 was secured in 1985.[8]

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ECONOMIC RECOVERY OF OIL TRAPPED AT FAN MARGINS USING HIGH-ANGLE WELLS AND MULTIPLE HYDRAULIC FRACTURES

Contract No. DE-FC22-95BC14940

Atlantic Richfield Company
Bakersfield, Calif.

Contract Date: Sept. 28, 1995
Anticipated Completion: Mar. 28, 1996
Government Award: $409,351

Principal Investigator:
B. Niemeyer

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

This project attempts to demonstrate the effectiveness of exploiting thin, layered, low-energy deposits at the distal margin of a prograding turbidite complex through use of fractured horizontal or high-angle wells. The combination of hydraulic fracturing and horizontal drilling will allow greater pay exposure than conventional vertical wells allow while maintaining vertical communication between thin interbedded layers and the wellbore.

A high-angle well will be drilled in the fan margin portion of a slope-basin clastic reservoir and will be completed with multiple hydraulic fracture treatments. Geologic modeling, reservoir characterization, and fine-grid reservoir simulation will be used to select the well location and orientation. Design parameters for hydraulic fracture treatments will be determined by fracture of an existing test well. Fracture azimuth will be predicted, in part, by passive seismic monitoring from an offset well during fracture stimulation of the test wellbore.

Summary of Technical Progress

An existing vertical well in Yowlumne field, Kern County, Calif., was hydraulically fractured. Microseismic and pressure data collected from this work are being used to predict fracture geometry and azimuth for future treatments in the proposed high-angle well.

A detailed reservoir characterization of the field demonstration site is complete. This work includes interpretation of a three-dimensional (3-D) seismic survey, analysis of all available well logs, description of three whole cores, petrographic analysis of thin sections, and incorporation of pressure and production data.

A partial-field fine-grid model based on the reservoir characterization has been constructed and initialized. Efforts to history match the model to actual production and pressure data are under way.

Fracture Characterization

Field operations associated with characterizing and designing hydraulic fracture treatments for the high-angle well are complete. This work includes fracturing a producing well, YUB 84-32, and monitoring the resulting microseismic events in a neighboring wellbore, YUB 86-32.

Both an unpropped mini-frac and a propped fracture treatment were pumped in YUB 84-32 to estimate fracture azimuth, fracture geometry, and other relevant design parameters. During these treatments, microseismic events were passively monitored in YUB 86-32 with the use of a clamped three-component geophone. Distance and direction of microseismic events generated by propagating the fracture were estimated from the difference in arrival times of P and S waves and by polarization of the P wave. This work represents one of the deepest (13,000 ft) and most widely spaced (1300 ft from wellbore to wellbore) tests of microseismic logging. Despite less-than-ideal subsurface conditions (Fig. 1), numerous events were detected during both treatments. The events are currently being analyzed to determine fracture azimuth.

Fluid pumped during the mini-frac treatment was tagged with a radioactive isotope. Temperature and gamma-ray logs run immediately following the treatment indicated that nearly all fluid exited the wellbore within a 40-ft section of the 200-ft reservoir interval. Only a small portion of the gross vertical section, therefore, appears to have been stimulated. An interpretation based only on log data potentially underestimates the vertical extent of the fracture because the fracture possibly grew in a different vertical plane than the north-south plane containing the deviated wellbore and therefore the fracture may not have intersected the well over its entire height. Pressure data, nonetheless, tended to agree with log results and indicated that the fracture was confined to a 35- to 40-ft interval.

Pressure data were also used to infer other common treatment design parameters, such as fracture gradient and leakoff coefficient. Interpretation of pressure decline data from the mini-frac suggested a very high fracture gradient, 1.05 psi/ft, as well as a very high leakoff coefficient, 0.014 ft/min$^{1/2}$. The high frac gradient was assumed to be the result of local compressional forces, whereas the elevated leakoff coefficient was thought to be the result of possible microfractures. Despite these adverse reservoir conditions, field operations continued forward, and the propped frac was successfully pumped to completion. Results from the propped frac generally corroborated the mini-frac interpretation (Fig. 2).

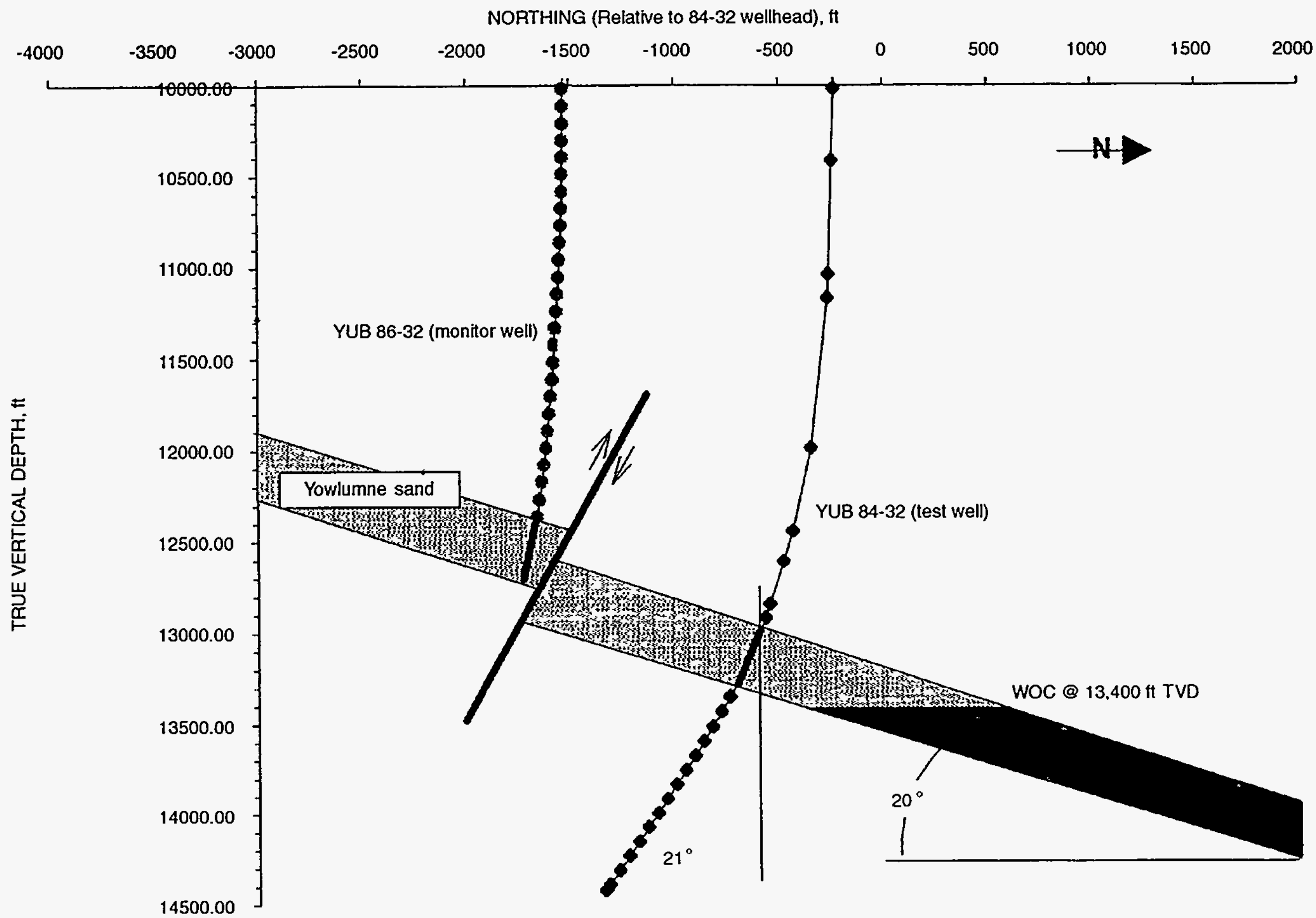

Fig. 1 North-south cross section through test and monitor wells. WOC, water–oil contact. TVD, true vertical depth.

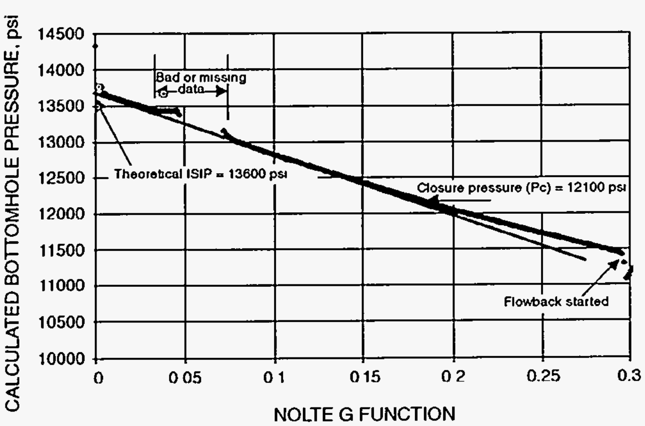

Fig. 2 G function plot for YUB 84-32 pressure decline. Fracture gradient, 1.06 psi/ft; leakoff coefficient, 0.013 ft/min$^{1/2}$; net pressure, 1500 psi; minimum horizontal stress, 0.92 psi/ft. ISIP, instantaneous shut-in pressure.

Reservoir Characterization

Characterization of the fan-margin area surrounding the expected well site is complete. This work includes description of 3 cores, petrographic analysis of 47 thin sections, modification of an existing petrophysical model, reinterpretation and refinement of hydraulic flow units, calculation of zonal averages, mapping of reservoir properties, and volumetric analysis of the project area.

Descriptions of over 280 ft of core taken from YUB 22X-3, 14X-3RD, and 46X-34 were completed by faculty and graduate students from the University of California–Santa Barbara (UCSB). The descriptions include observations of sedimentological characteristics, correlations to the Bouma[1] vertical sequence, and identification of Mutti and Ricci Lucchi[2] turbidite facies. The descriptions also include comparison of lithofacies to log response to aid in identification of rock types from logs.

Petrographic analyses of thin sections were also completed by UCSB. This work helped to qualitatively describe the reservoir's effective porosity, detrital mineralogy, and secondary mineralogy. Findings indicate that the effective porosity results primarily from the compaction of original depositional porosity with only subtle diagenetic alteration. Additionally, no significant stratigraphic or lateral variation in mineralogy could be identified except for an isolated chert-cemented zone located near the top of the reservoir interval.

Review and modification of an existing petrophysical model have also been completed. Data from three cores were used to evaluate the accuracy of the log model in estimating shale volume, porosity, water saturation, and permeability for the fan margin. In general, the model adequately represents most rock properties. Several modifications, however, were needed to improve correlation between core and log permeabilities.

Following modification of the log model, hydraulic flow unit correlations were reinterpreted for the project area. Flow units were identified primarily from log response, production and injection profiles, and RFT pressure measurements. Ten flow units were correlated within the project area (Fig. 3).

Reservoir property averages were then determined for each flow unit for 32 wells in the project area. Only intervals meeting net sand criteria ($V_{sh} < 0.30$, $\phi_{eff} > 0.08$) were included in the averages. Zonal averages were then mapped over the entire project area. Sand edges, as interpreted from a 3-D seismic survey, were used to constrain mapping algorithms.

Volumetric analysis of the mapped project area was also completed. On the basis of this work, original fluids

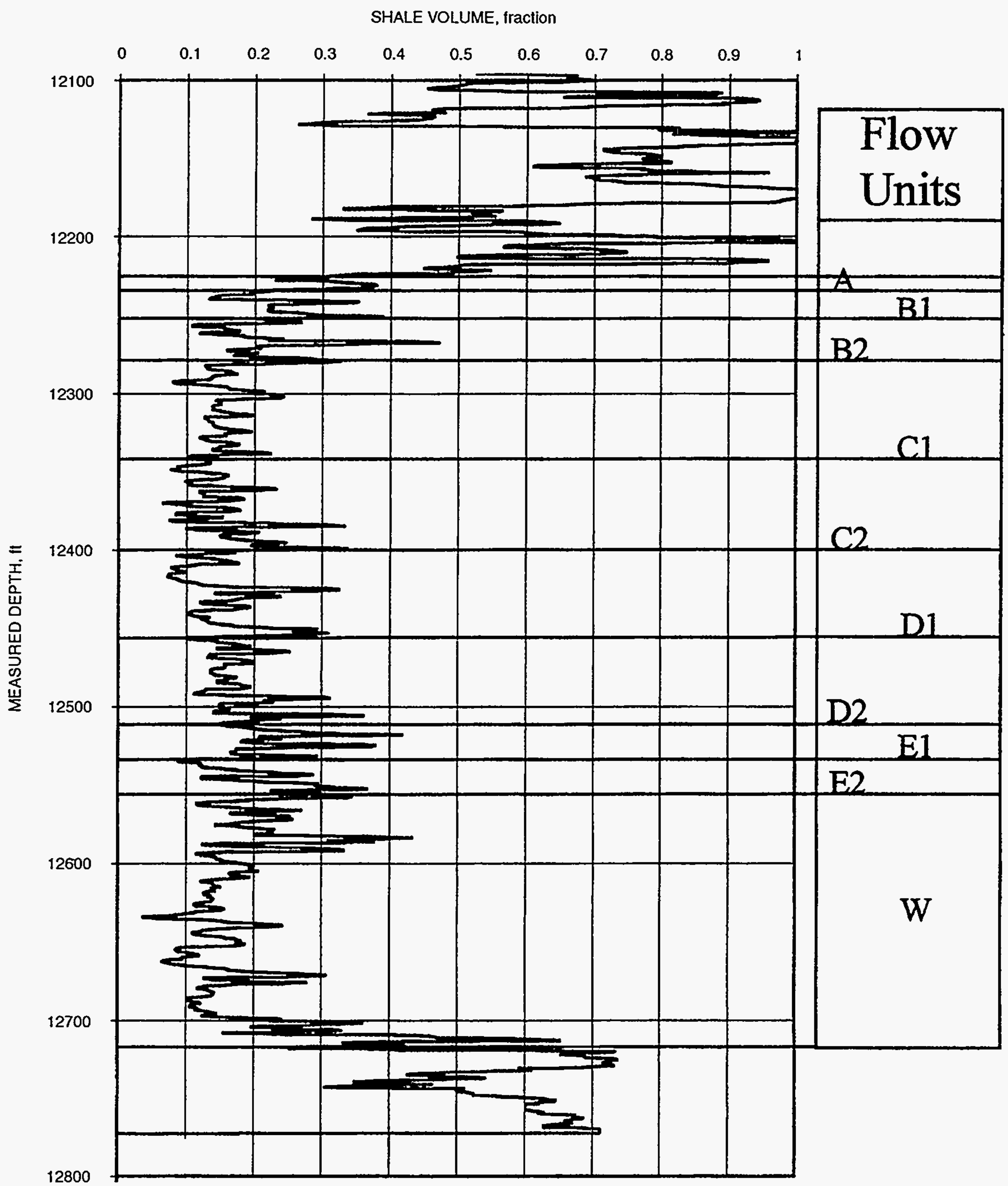

Fig. 3 Yowlumne sand flow units with YUB 27X-34 shale volume curve.

in place are estimated to be original oil in place (OOIP), 74.3 million barrels (MMB); original gas in place (OGIP), 44.7 million cubic feet (MMCF) (solution gas); and original water in place (OWIP), 63.0 MMB. The OOIP determined for the project area represents approximately 31% of the total field OOIP.

Reservoir Modeling

A fine-grid 3-D model was constructed and initialized using the fan-margin reservoir description. Efforts to match model performance to historical primary and waterflood pressure and production data are under way.

A fine-grid 34 × 34 × 10 model lattice has been constructed for the project area (Fig. 4). Within the lattice, each flow unit is represented by an individual layer, and areal boundaries are defined to correspond with the eastern sand edge and three approximate no-flow boundaries, as determined from streamline models. Areal cell sizes are designed to provide at least six cell interfaces between adjacent injectors and producers.

Model saturation and fluid properties are based on experimental data from the project area. These data include black oil fluid studies, unsteady state water–oil and gas–oil relative permeability tests, and air–brine porous plate capillary pressure measurements.

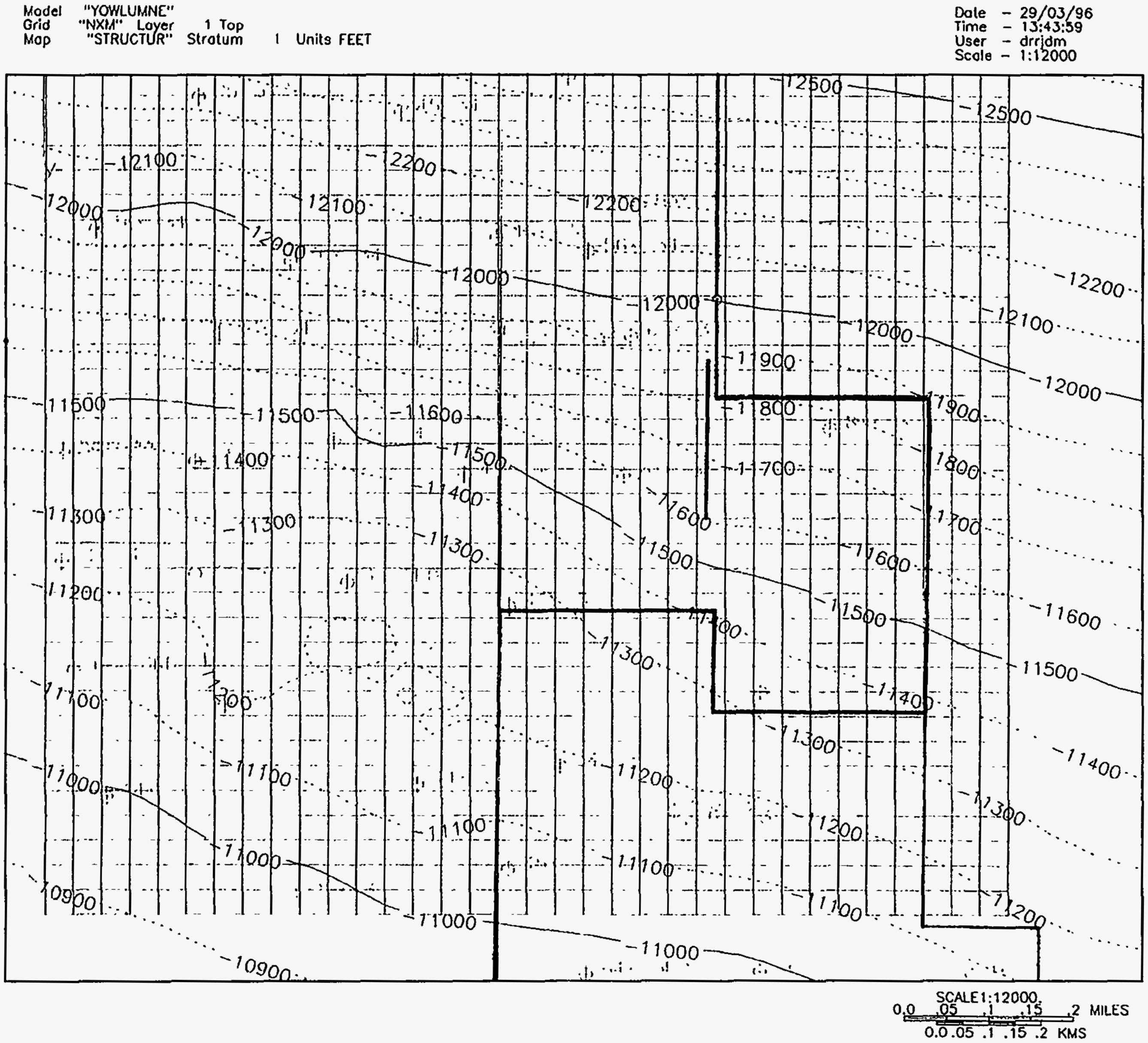

Fig. 4 Project area covered by 34 × 34 × 10 model lattice. (Art reproduced from best available copy.)

Model rock properties, except for initial fluid saturations, are drawn directly from the reservoir description. In order to prevent equilibration problems, initial fluid saturations are estimated in the model with the use of fluid contacts and a J-function on the basis of experimental capillary pressure data.

Following construction of the model lattice and compilation of basic reservoir data, the model was initialized and fluid volumes compared to integrated map volumes. No model adjustments were needed to match the mapped volumes.

When model initialization was completed, work was begun to history match the model to actual field performance. Within the model, oil production rates and water injection rates are explicitly specified. The model will be adjusted to match water and gas production rates, average reservoir pressures, and producing bottomhole pressures (BHPs).

Early history-match efforts indicate that, despite the model's fine grid, numerical dispersion still impacts performance because model water/oil ratios (WORs) are significantly higher than actual WORs. Water–oil relative permeability curves will be altered to offset dispersion effects.[3] Additional history match adjustments will potentially include boundary flux curves, which will be estimated from a history-matched full field model, and adjustment of well completion skins to match producing BHPs.

After an approximate history-match is completed, ARCO intends to apply local grid refinement to the immediate area surrounding the proposed high-angle well. Once a nested grid is included in the model, the solution method will be switched from IMPES to fully implicit. The history match will then be updated for the altered grid and solution technique. The model will then be used to predict performance of the high-angle well.

Technology Transfer

Project objectives and preliminary results were presented at a well stimulation forum held in Girdwood, Alaska, during the week of March 11–15. The forum, hosted by ARCO Alaska Inc., was attended by representatives from more than 20 companies and universities.

Work is currently under way to establish an open file with the California Division of Oil, Gas and Geothermal Resources (DOGGR). The file will be available to the general public through DOGGR.

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THE USE OF INDIGENOUS MICROFLORA TO SELECTIVELY PLUG THE MORE POROUS ZONES TO INCREASE OIL RECOVERY DURING WATERFLOODING

Contract No. DE-FC22-94BC14962

Hughes Eastern Corporation
Jackson, Miss.

Contract Date: Jan. 1, 1994
Anticipated Completion: June 30, 1999
Government Award: $547,413
(Current year)

Principal Investigators:
Lewis R. Brown
Alex A. Vadie

Project Manager:
Rhonda Lindsey
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this work is to demonstrate the use of indigenous microbes as a method of profile control in waterfloods. It is expected that, as the microbial population is induced to increase, the expanded biomass will selectively block the more permeable zones of the reservoir. This will force injection water to flow through the less permeable zones and improve sweep efficiency.

This increase in microbial population will be accomplished by injection of a nutrient solution into four injectors. Four other injectors will act as control wells. During Phase I, two wells will be cored through the zone of interest. The core will be subjected to special core analyses in order to arrive at the optimum nutrient formulation. During Phase II, nutrient injection will begin, the results will be monitored, and adjustments to the nutrient composition will be made, if necessary. Phase II also will include the drilling of three wells for postmortem core analysis. Phase III will focus on technology transfer of the results. One expected outcome of this new technology will be a prolongation of economical waterflooding operations (i.e., economical oil recovery should continue for much longer periods in the producing wells subjected to this selective plugging technique).

Summary of Technical Progress

Phase I: Planning and Analysis

The concepts for the new technology to be evaluated in this project are scientifically sound and have been proven to be effective in laboratory experiments. Nevertheless, it was necessary to perform laboratory tests on live cores from the reservoir of interest. Two wells were drilled for this purpose, and special core analyses were conducted in order to fine-tune the exact concentration of, and schedule for, additions of nutrients to the injection water.

Whereas the main purpose for drilling the two wells was to obtain cores suitable for use in the laboratory work, a secondary purpose was to obtain production data on the sweep efficiency of the existing waterflood. By the conclusion of Phase I, a specific feeding regime will be formulated for each of the injection wells. Because the injection wells all vary in terms of years of service, differences in channeling are anticipated and a different feeding regime may be needed for each well.

The work for Phase I of the project has been divided into seven tasks. The first five, which are complete, are the drilling of two new injection wells for the acquisition of cores and other data, on-site handling of cores, core analysis to determine microbial enhanced oil recovery (MEOR) requirements, microbial analyses of cores, and laboratory waterflooding test of live cores.

The last two tasks of Phase I were continued this quarter.

Acquisition of Baseline Data

Chemical and microbiological analyses of injection water and production fluid are continuing and have been expanded to include all four patterns. Test patterns (control and test) involve 8 injectors, 23 producers, and 2 newly drilled wells. Routine tests being conducted on the water are calcium carbonate, chloride, nitrate–nitrogen, phosphate, potassium, sulfate, sulfide, aerobic heterotrophs, anaerobic heterotrophs, aerobic oil-degrading bacteria, and anaerobic oil-degrading bacteria. Routine tests on oil are aliphatic profile, gravity, viscosity, and surface and interfacial tension. Test data received from Hughes Eastern Corporation for wells located in all patterns (test and control) were entered into the database for gas/oil ratio (GOR) and water/oil ratio (WOR) calculation.

Analysis of Baseline Data

The analysis of baseline data is continuing.

Phase II: Implementation

Nutrient injection and the analysis of results (the implementation phase) have begun.

Design of Field Demonstration

During the current quarter, nutrient injection continued with few problems. The test pattern waterflood injection rates range from 330 barrels of water per day (BWPD) in the 34-9 No. 2 well (test pattern 2) to 700 BWPD in the 11-5 No. 1 well (test pattern 3). Test patterns 1 and 3 receive the nutrients potassium nitrate and monosodium hydrogen phosphate; test patterns 2 and 4 receive molasses in addition to the other nutrients. Test patterns 1 and 3 exhibit a downward trend in injectivity, which may indicate microbial growth causing permeability restriction. The other two test patterns are injecting at a relatively constant rate. Consistent increases in oil production have occurred in some wells.

In March, a project coordination meeting was held to discuss changes to the nutrient injection schedule which might speed the microbial process. It was decided that an increased rate of molasses addition would result in the greatest response per volume of nutrient injected. Effective April 1, 1996, the molasses injection rate in test pattern 4 (NBCU 2-6 No. 1) is to be increased to 35 gal/week and the midweek phosphate injection in test pattern 1 (NBCU 2-14 No. 1) is to be replaced by 35 gal of molasses. The increased molasses injection will provide a carbon source for the microbes which is more easily metabolized than crude oil.

Analysis of produced water in test pattern 1 continues for detection of the tritium tracer injected on April 27, 1994. To date, the tracer has been detected in the 2-13 No. 1 and 11-3 No. 1 wells.

Reservoir Characterization

Petrophysical studies of recovered core sample from newly drilled wells continue.

Analysis of Results

More chemical and microbiological analyses are being conducted on samples from wells in all patterns. Gas chromatographic data from all patterns continue to be evaluated for evidence of microbial activity. Also, nitrate–nitrogen, found in the fluid from one of the test wells as reported last quarter, has not been found in any more samples and therefore is not considered significant. Nitrate-reducing organisms should be stimulated by the nutrient additions and are being found in samples from several wells in the first two test patterns. They are also found in some injection water samples and therefore are of questionable significance. Tests for this physiological group of microorganisms are now being conducted monthly. Other chemical, microbiological, and petrophysical parameters of fluids from injector wells (8) and producer wells (25) are still being monitored. To date, none of the parameters being monitored by laboratory analyses have demonstrated changes that definitely can be attributed to microbial activity in the reservoirs.

It was decided to carry out coreflood experiments in the laboratory that parallel the feeding regimes now being employed in the field, particularly since the amount of nutrients has been increased. Six new core plugs were prepared from the last remaining cores obtained from the recently drilled well (34-3 No. 2). The core plugs are being monitored with emphasis on flow rate through the plugs.

Publication

A manuscript entitled "Utilization of Indigenous Microflora in Permeability Profile Modification of Oil Bearing Formations" has been submitted for presentation at the SPE/DOE Tenth Symposium on Improved Oil Recovery to be held in Tulsa, Okla., April 22–24, 1996.

ADVANCED OIL RECOVERY TECHNOLOGIES FOR IMPROVED RECOVERY FROM SLOPE BASIN CLASTIC RESERVOIRS, NASH DRAW BRUSHY CANYON POOL, EDDY COUNTY, NEW MEXICO

Contract No. DE-FC22-95BC14941

Strata Production Company
Roswell, N. Mex.

Contract Date: Sept. 25, 1995
Anticipated Completion: Sept. 25, 2000
Government Award: $1,786,163

Principal Investigator:
Mark B. Murphy

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The overall objective of this project is to demonstrate that a development program based on advanced reservoir management methods can significantly improve oil recovery. The demonstration plan includes development of a control area with standard reservoir management techniques and comparison of the performance of the control area with an area developed with advanced reservoir management methods. Specific goals are to (1) demonstrate that a development drilling program and pressure maintenance program, based on advanced reservoir management methods, can significantly improve oil recovery compared with existing technology applications and (2) transfer the advanced methodologies to oil and gas producers in the Permian Basin and elsewhere in the U.S. oil and gas industry.

Summary of Technical Progress

Management and Project Planning

The geological, engineering, simulation, and management project teams held three meetings during the quarter to develop a project plan for the reservoir characterization/simulation team. Also, consolidation of interests and buyout of small interest owners has been initiated. A block of interests representing approximately 23% of the working interest owners has been consolidated. This will help simplify management of the project.

Geology

Data for mapping and calibration were compiled. Logs were correlated within the field to establish an initial stratigraphic and structural framework for the basal Brushy Canyon sands in the Nash Draw Unit. The basal Brushy Canyon has been subdivided (by prior work) into four mappable stratigraphic units. Designated the J, K, K-2, and L sands, all four units are productive and fall within the scope of this project.

For mapping and comparison, various log data have been compiled for each sand. These data include gross interval isopach thickness, ϕ_h values (net thickness for porosity >14%), and core porosity vs. log porosity data. The data were then used to prepare the following initial suite of maps:

- 5 structure maps (J, K, K-2, L, and top of Bone Spring limestone)
- 5 gross interval isopach maps (J, K, K-2, L, and top of Bone Spring limestone)
- 4 net porosity maps =14% ϕ_D (J, K, K-2, L), where ϕ_D is density porosity
- 4 ϕ_h maps with 12% or greater ϕ_D (J, K, K-2, L)

These maps will serve as the basis for geological modeling in the field. The reservoir simulation group will use the maps to develop a preliminary geologic framework for their modeling. The calibration of core data to log data will determine what are pay quality sands. These data will help define the net available reservoir within each of the primary pay zones and will also help establish parameters for pay in other logs where core data are not available.

The geophysical group is using the maps to help develop a seismic model. Once the three-dimensional (3-D) seismic is processed, the geological and geophysical models can be combined and refinements made. Discussions with the geophysical group concerning depositional environments, seismic attributes, and mappability of the individual sands have begun.

Pilot Area

Detailed geologic mapping within the proposed injection pilot area began. The Nash 1, 5, 6, 10, and 14 wells were posted on a cross section. The gross interval correlation for the sands from well to well were established previously, and a more detailed mapping approach was taken. The K, K-2, and L sands were subdivided into K_A, K_B, K_C, and K_D (K sand); K-2_A, K-2_B, and K-2_C (K-2 sand); L_A, L_B, L_C, and L_D (L sand).

A gross isopach map has been generated for each of the subunits in the pilot area which will help in the development of cells for reservoir simulation. Core and log data are being added to help define pay intervals within each of the subunits. The results from the pilot area will be expanded throughout the rest of the field. The detailed correlation and mapping has shown that each of the gross sand intervals is actually a composite of multiple, stacked *micro* reservoirs. Additional work will be done in an attempt to correlate these *micro* reservoirs from well to well.

Production Analog

Preliminary data gathering in the portion of the Loving East analog area has begun. This field was chosen because the geologic and reservoir characteristics are similar to those of the basal Brushy Canyon in the Nash Draw Unit. Mapping will begin early in the second quarter of 1996.

The analog area has been identified, and preliminary data acquisition has begun. The area being reviewed is sec. 14, T. 23 S., R. 28 E. in the East Loving Brushy Canyon pool. This section has 16 Brushy Canyon producers with cumulative oil production ranging from 51,000 to 168,000 bbl, which provides a wide variety of well types and structural positions for analysis. Well logs, production plots, and preliminary mapping are complete.

Engineering

The third data well, the Nash Draw 25 located 500 ft from the east line and 165 ft from the south line of sec. 14, was drilled in February. It encountered a well-developed K sand, high water saturations in the K-2 sand, and a thin L sand with only 4 ft of net pay. Before the well was fractured, a bottom-hole pressure buildup test was performed to determine permeability and formation damage. With an assumption of 40 ft of net pay, this test indicated a permeability of 0.81 mD. This well is being completed and should be on production by mid-April 1996.

The database has been updated with the addition of digitized logs, digitized core data, and production and decline curves current through February 1, 1996. Preliminary calibration of the production volumes has begun, and anomalies are being resolved. The simulation team has received the first copy of the database and is processing the data into the reservoir simulator.

The full core analysis and scanning electron microscope (SEM) data have been reviewed in detail. The relative permeabilities indicate that the permeability to water at the residual oil saturation may be too low to make water injection a practical method of pressure maintenance. A modification to the statement of work was made to eliminate the second core and substitute additional fluid swelling tests to determine the effectiveness of gas injection for pressure maintenance. These tests will be performed during the next quarter.

Vertical Seismic Profiles

Two vertical seismic profiles (VSPs) were recorded in the Nash Draw 25 well. One Litton 315 vibrator was positioned 255 ft southeast of the well (127° azimuth) to produce zero-offset VSP data, and a second Litton 315 vibrator was stationed 2178 ft north of the well (349° azimuth) to create a far-offset VSP. The Nash Draw far-offset VSP image is displayed in Fig. 1 as a function of stratigraphic depth to better correlate with wireline-measured log and core data.

The log-interpreted depths of the tops of the J, K, K-2, and L reservoirs in the No. 25 well are 6598, 6639, 6737, and 6765 ft, respectively, where all depths are measured relative to the kelly bushing. Two of these reservoirs, K and L, are of particular interest at the No. 25 well because the K reservoir was well developed but the L reservoir was not. The depth positions of the K and L reservoirs are labeled in the VSP image in Fig. 1 together with the position of the Bone Spring limestone, which is immediately below the L sandstone.

An important insight provided by these VSP data is that the closely spaced K and L reservoirs are defined as separate seismic features when the illuminating wavelet has a bandwidth of at least 8 to 96 Hz. The VSP image shows that the K reservoir creates a reasonably strong reflection peak at the No. 25 well, whereas the L reservoir generates a weaker reflection trough. Seismic modeling will be required to establish if there is a definitive correlation between reservoir properties of the K and L units and seismic reflection amplitude; however, seismic modeling at Nash Draw is handicapped because only one sonic log is available for calculating synthetic seismograms.

The reflection character of both the K and L events, as it appears at the well (the rightmost trace of the image), changes significantly about 100 ft north of the well (the 5th and 6th trace from the right side of the VSP image), which implies that some type of variation in the reservoir system occurs at this location. Again, seismic modeling, or the careful integration of geologic control with 3-D seismic interpretation, will be required to establish the stratigraphic and rock-property messages implied by such variations in seismic facies. The VSP image also shows that the reflection trough associated with the L reservoir has a slightly greater amplitude (brightens) at location A, about 200 to 300 ft north of the well, and that at location B, about 500 to 650 ft north of the well, the amplitudes of both the K reflection peak and the L reflection trough become noticeably stronger. These reflection amplitude variations are direct indicators of stratigraphic changes,

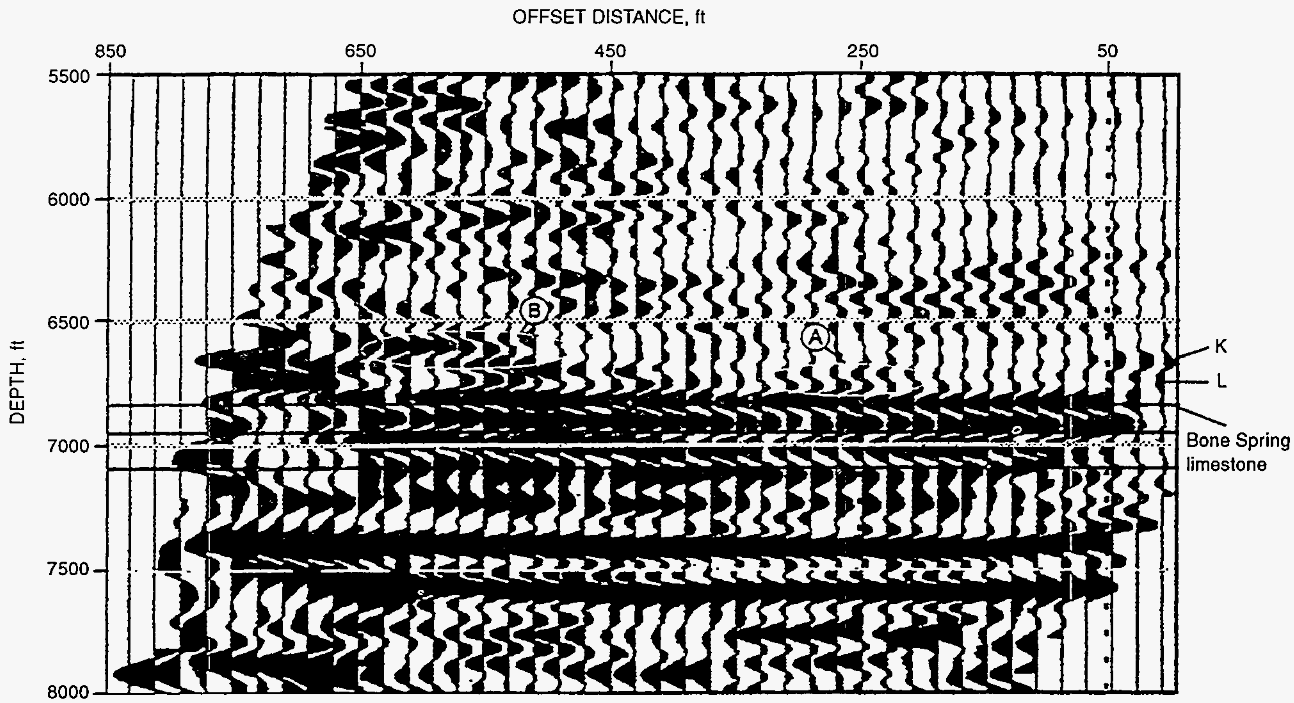

Fig. 1 Interpretation of vertical seismic profile image. The positions of the closely spaced K and L reservoirs and the high-amplitude Bone Spring limestone reflector are labeled.

or facies changes, or both, within the J, K, K-2, and L reservoir systems. These variations in the reflection amplitude of the VSP image indicate that considerable changes in 3-D seismic reflection attributes will occur across this heterogeneous reservoir system.

The far-offset VSP data were processed so that the stacking bins used in the image construction had a horizontal width of only 20 ft. Consequently the trace spacing in the image displayed in Fig. 1 is 20 ft. Much of the lateral variation in reflection waveform character that occurs in this image is the result of the small width of the VSP stacking bins (that is, the trace spacings in the image). The stacking bins that were to be created in the original 3-D seismic geometry, which was sent out for bids, covered an area measuring 110 × 110 ft. In such a geometry, each 3-D seismic trace would thus have been equivalent to the trace that would be created by summing five adjacent traces in the VSP image in Fig. 1. In the 3-D image resulting from this acquisition geometry, the stratigraphy extending 870 ft north of the No. 25 well would be defined by only 8 traces; that same stratigraphy is defined by 44 traces in the VSP image in Fig. 1.

One important result of this initial VSP imaging effort is that it revealed that smaller stacking bins would have to be created in the 3-D seismic data volume if the 3-D data are to show lateral changes in the reservoir that are of the size seen in the VSP images. Consequently, as a result of the VSP work, the Nash Draw 3-D seismic grid has been redesigned to produce acquisition bins measuring 55 × 110 ft. During data processing, a trace interpolation will be done in the source line direction to create interpretation bins measuring 55 × 55 ft.

A key conclusion of this vertical wavetest is that high-quality seismic data can be recorded at Nash Draw field. Essentially all the signal components of each test wavelet survived the downward trip to the targeted stratigraphy at a depth of 7000 ft.

Reservoir Characterization/Reservoir Simulation

Efforts for the first quarter of 1996 centered on preparations for evaluating three alternative enhanced recovery methods for the field pilot planned for the last quarter of 1996. Three methods are currently under consideration: (1) immiscible lean gas injection, (2) waterflooding, and (3) CO_2 injection. Major effort was devoted to the development of a geological model for the Unit; however, some time was spent inventorying and assessing the completeness of the data available to support the modeling work and installing the project's two new computers (an SGI Indigo2 with high-impact graphics and a Pentium 166 PC).

Simulation of the pilot was initiated with the present geological interpretation of the Nash Draw Unit prepared by the project geology team. This interpretation exists in the format of maps of Unit attributes for five zones: J, K, K-2, L, and the interval between the bottom of L and the top of the Bone Spring limestone. For each of these sands, the following attributes have been mapped: (1) top of structure, (2) gross isopach, (3) porosity–thickness, and (4) net porosity. These maps have been digitized for input into the Stratigraphic

Geocellular Model (SGM), which permits full 3-D representation of the Nash Draw Unit. In turn, SGM supports spatial statistical analysis and the geological component of reservoir simulation.

The future availability of 3-D seismic data will permit the development of a second-generation geological model. Such data may support the use of sophisticated linear estimation methods such as co-kriging and stochastic simulation. The present model will be based on the use of kriging to estimate reservoir properties.

The team envisions the pilot simulation model to be a full-field model from inception. The unstructured gridding options available in the flow simulators under consideration will be exploited to coarsen the flow model away from the pilot. Although the present interpretation of the Unit has identified only five significant lithological units, the simulation model is expected to exhibit additional vertical segmentation in order to treat gravity effects.

3-D Seismic

Permitting and surveying for the 3-D seismic program are about 80% complete. The 3-D seismic program design is almost complete.

Technology Transfer

On February 23, 1996, a working interest owners' meeting was held to bring owners up to date and to start the organization of a technical committee. A preliminary membership list of the technical committee was agreed on and is being finalized. A list of potential members for the Liaison Committee has been prepared and is being sent to prospective members.

INCREASING HEAVY OIL RESERVES IN THE WILMINGTON OIL FIELD THROUGH ADVANCED RESERVOIR CHARACTERIZATION AND THERMAL PRODUCTION TECHNOLOGIES

Contract No. DE-FC22-95BC14939

City of Long Beach
Long Beach, Calif.

Contract Date: Mar. 30, 1995
Anticipated Completion: Mar. 29, 1999
Government Award: $3,408,216

Principal Investigator:
Scott Hara

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this project is to improve thermal recovery techniques in a slope and basin clastic (SBC) reservoir in the Wilmington field, Los Angeles County, Calif., with the use of advanced reservoir characterization and thermal production technologies.

Summary of Technical Progress

Compilation and Analysis of Existing Data

Digitized and normalized log data for 171 wells, which are distributed throughout the fault block, are available for use in the basic reservoir engineering and geologic stochastic models. The digitized logs include the electric or induction and the spontaneous-potential (SP) and/or gamma-ray (GR) logs.

Advanced Reservoir Characterization

Basic reservoir engineering continued. Work is continuing on the evaluation of the aquifer for water influx, determination of original oil in place from gas saturations to support the material-balance work, and correlation studies on projected steam-drive recoveries from vertical and horizontal wells.

The tracer program has been delayed because the main hot-water distribution line was temporarily disconnected to accommodate the surface landowner. Also, one of the non-radioactive reservoir tracers selected, ammonium nitrate, is unstable and unsafe under certain surface conditions, so a substitute will be chosen. The two tracers will be bulk injected into the T and D zones in July, when the hot-water system will be reconnected. The tracers will follow the liquid phase of the injected steam.

Three observation wells and two core hole–observation wells were drilled. Four of the wells are for monitoring reservoir temperatures in the horizontal well steam-drive pilot area. The D1 subzone is the steam-drive interval for the horizontal wells. The fifth well is located in the original pilot steam-drive area to determine post-steam oil saturations and mineral alterations to the formation rocks. Core recovery through the T and D subzones was excellent; over 99% of the planned core interval of 517 ft was recovered. The plan is to perform conventional porosity, permeability, and oil saturation measurements on core plugs. A proposal has been completed on high-temperature core work to determine residual oil saturations to different steam temperatures, formation rock and fluid alterations caused by different steam temperatures, and the physical phenomena behind the successful perforated well completions in unconsolidated sands when initially stimulated with steam. Core work will commence in June.

Refinements to the geologic deterministic model, such as re-evaluating the fault picks and increasing the defined sand tops in the tar zone from 10 to 18, were completed in the first quarter of 1996. All existing core data were visually inspected in order to develop a core-based log model. The model, which will incorporate the two new cored wells, will be completed in April 1996. The core-based log model will be used for developing the porosity–permeability model and rock–log model.

Other deterministic geologic studies under way include the barrier characteristics of the geologic faults and the correlation of the stratigraphic characteristics of the tar zone with similar deposits in neighboring fields. Both of these studies should be completed in the first half of 1996.

A neural network analyzer has been developed on the stochastic geologic model to analyze the similarities of various zones and subzones in terms of sequence stratigraphy with the use of GR logs. Sample stochastic grid-block models are being test run on the three-dimensional (3-D) EarthVision™ visualization software to ensure compatibility. An abstract submitted for this work was accepted for a paper presentation at the 1996 Fall Meeting of the Society of Petroleum Engineers (SPE) in Denver.

Reservoir Management

The 2400-ft steam transmission line under the Cerritos Channel was placed in service in mid-December. A low initial steam rate of 300 bbl of cold-water-equivalent steam per day (BCWESPD) was delivered to allow the line to expand slowly. Through the end of March, the steam line had performed very well with no problems. In review, the steam line included a 42-in. bore under the channel, a 30-in. outer line that was pulled through the bore and cemented in place, and dual concentric lines consisting of a 14-in. insulated steam line inserted inside a 24-in. backup line that were pulled through the 30-in. line together.

Injection rates for the four hot-water injection wells ranged from 2000 to 3000 BCWESPD during this quarter. There has been no production response to date.

Detailed thin-section, scanning-electron-microscope, and X-ray-diffraction work on wellbore fill samples from the existing steam-drive wells shows several types of scales, including calcites, dolomites, barites, anhydrites, and magnesium silicates. A study of the cores, produced fluids, and injection water that determines the mineralogy and source of the scales and how to prevent their occurrence is complete. The study will be presented at the SPE/DOE Improved Oil Recovery Symposium in Tulsa in April 1996 and at the 1996 American Association of Petroleum Geologists convention in San Diego in May 1996. Design of high-temperature laboratory work on the cores was completed in December. Actual high-temperature laboratory work on the cores will begin in June 1996.

Technology Transfer

The goal of the project team is to present each technical advance within 12 months of its completion at a professional society meeting or convention. These technological advances will be highlighted in a CD-ROM of the project scheduled for the third quarter of 1996 and on a new home page for the project to be created on the Internet. The technology transfer commitment for this and other Department of Energy projects has led the project team members to establish a Regional Lead Organization office of the Petroleum Technology Transfer Council at the University of Southern California and to restructure the Western Regional Meeting of the Society of Petroleum Engineers to provide more practical and timely presentations to a broader industry audience.

RESEARCH PROGRAM ON FRACTURED PETROLEUM RESERVOIRS

Contract No. DE-FG22-93BC14875

Reservoir Engineering Research Institute
Palo Alto, Calif.

Contract Date: Sept. 30, 1993
Anticipated Completion: Sept. 29, 1996
Government Award: $447,000

Principal Investigators:
Abbas Firoozabadi
Mehran Pooladi-Darvish

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The main objective of this project is to fully understand the role of diffusive, capillary, gravity, and viscous forces in the flow of fluids in fractured porous media. The plan is to conduct a comprehensive experimental and theoretical research program to better understand the basic mechanisms of oil recovery and recovery enhancement of fractured petroleum reservoirs.

Summary of Technical Progress

A review of the literature indicates that imbibition in water-wet matrix blocks is commonly considered to be countercurrent; however, experimental and theoretical studies indicate that co-current imbibition may be the dominant mechanism.[1] Therefore a numerical model was developed to study co-current and countercurrent imbibition at early and late times in finite porous media. The method of Douglas et al.,[2] discussed by Peaceman,[3,4] was used to develop one-dimensional and two-dimensional finite-difference models. With the use of these models, oil was found to be mainly recovered by co-current imbibition, and the recovery time was only a fraction of that required for countercurrent imbibition because in countercurrent imbibition oil is forced to flow in the two-phase region. In co-current imbibition, however, the oil is free to flow in the single-phase region. In this study, co-current and countercurrent imbibition are compared, and the comparison reveals that co-current imbibition is much more efficient than countercurrent imbibition.

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IMPROVED RECOVERY DEMONSTRATION FOR WILLISTON BASIN CARBONATES

Contract No. DE-FC22-94BC14984

Luff Exploration Company
Denver, Colo.

Contract Date: June 10, 1994
Anticipated Completion: Dec. 31, 1997
Government Award: $1,778,014

Principal Investigators:
Mark A. Sippel
Larry A. Carrell

Project Manager:
Chandra Nautiyal
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The objectives of this project are to demonstrate targeted infill and extension drilling opportunities, better determinations of oil in place, methods for improved completion efficiency, and the suitability of waterflooding in certain shallow-shelf carbonate reservoirs in the Williston Basin, Montana, North Dakota, and South Dakota.

Summary of Technical Progress

Field Demonstrations

Ratcliffe Reservoir

The drilling of a horizontal lateral in the Ratcliffe reservoir from a cased hole was unsuccessfully attempted during January in the Trudell M-17, sec. 17, T. 26 N., R. 58 E., Richland County, Mont. The drilling technology was developed by Amoco.[1] The drilling failed immediately upon initiating drilling of the curved portion of the hole through the casing window because of a mechanical failure of the bottomhole drilling assembly. The drilling depth of 8500 ft is apparently beyond practical limits for this technology.

A pair of Ratcliffe completions in sec. 16, T. 26 N., R. 58 E., Richland County, Mont., offered the greatest potential for additional recovery by improved completion efficiency and water injection. From material-balance calculations aided by computer simulation and production type-curve analysis, nearly 5,000,000 bbl (795,000 m^3) of original oil in place (OOIP) was estimated. Recovery from these wells is approximately 150,000 bbl (23,800 m^3); remaining economic reserves are only 40,000 bbl (6400 m^3). This recovery represents only 4% of the potential OOIP. Oil productivity and porosity development at these two wells is normal for the area. The distance between these wells is approximately 0.25 mile (0.4 km) and should be suitable for testing water injectivity and secondary response.

Preparations are being made to drill a lateral from the 2-16 State with steered-motor technology. The well will be used for water injection in a pilot waterflood evaluation. Contingent upon the mechanical success of drilling operations at the 2-16 State, the technology may be used at the Trudell M-17.

Buffalo Field (North Area)

Engineering studies are complete for evaluation of horizontal drilling and waterflooding in the north area of Buffalo field, Harding County, S. Dak. Luff Exploration Company has petitioned the South Dakota Oil and Gas Conservation Board for a hearing in June to drill a horizontal well in sec. 20, T. 22 N., R. 4 E. Drilling will start soon after the board grants approval. Reprocessed two-dimensional (2-D) seismic data will be used to guide placement and trajectory of the lateral. The horizontal well will test water injectivity and is to be drilled midway between two existing wells in sec. 20 on 320-acre (129-ha) production units. The horizontal injection well and two producers will comprise a pilot waterflood for the Red River "B" reservoir.

Geophysical Evaluations

Ratcliffe Reservoir

A 2-D multicomponent seismic line was acquired over Cattails (Ratcliffe) field in Richland County, Mont. Adequate data do not exist on the processed horizontal components to evaluate applicability of converted-wave methodology for fracture detection and characterization or to measure shear-wave splitting because processing was halted before an optimal final product was achieved.

Feasibility evaluations are under way to reprocess the data by Pulsonics Seismic Processors in conjunction with other nearby 2-D conventional compressional (P)-wave data. From these data sets, an evaluation would be made of the merits of shear (S) and P-wave data as discriminators of Ratcliffe reservoir development. The Cattails study will guide future seismic-characterization efforts for the Ratcliffe. A three-dimensional (3-D) seismic survey over North Sioux Pass is scheduled for this year. Pending results from the Cattails multicomponent reprocessing and evaluation, additional shear-wave recordings may be included in this acquisition.

Red River Reservoir

The 3-D seismic data acquisition at Cold Turkey Creek, Bowman County, N. Dak., was given to two geophysical interpretation companies for analysis. Seismic picks were made at the Greenhorn, Mission Canyon, Duperow, Interlake, Red River, and Winnipeg. Time structure and isochron interpretations were made. Faulting was picked at Winnipeg and Red River events. Both interpreters found it necessary to rotate the 3-D data volume to match the synthetic seismograms. One group rotated the data –120°; the other determined that a –90° rotation provided a normal polarity, zero-phase data volume. The Cold Turkey Creek data were acquired with dynamite shots as sources. Faulting was interpreted by both groups to affect the Winnipeg to a greater degree than the Red River, and most faults terminate in the Red River or slightly above the Red River. The predominant fault orientation is slightly west of north 315°). Faults are low relief and are generally 0.25 to 0.5 mile in length (0.4 to 0.8 km). P-wave attributes and isochrons were used for geostatistical correlation with thickness and porosity development in the Red River. Conclusions regarding stratigraphical correlations of Red River development with 3-D seismic attributes were mixed and inconclusive from both groups.

The 3-D data from Cold Turkey Creek were processed by Coherency Technology Corp. for incorporation with conventional faulting and stratigraphic interpretations. The coherency-cube transform is generated by analyzing localized waveforms in both the in-line and cross-line directions. Coherence is lower where traces are less similar. Displays of coherency values in map view of time or horizon slices can depict stratigraphic changes or subtle faults.[2,3] It was determined from both interpretation groups, however, that the coherency-processed data did little to enhance the final fault interpretation or stratigraphical analysis of the Red River.

It has been concluded that a well should be drilled in the northern area of the Cold Turkey Creek 3-D survey; however, the 3-D data are being reprocessed and will be reinterpreted before the final location is selected.

A 3-D seismic survey will be acquired at the Grand River School (Red River) field in Bowman County, N. Dak. Permits are being obtained, and the shoot will probably occur in late May, depending on the weather and planting of crops.

Reprocessing of 2-D seismic data from the 1980s is under way across portions of Buffalo field (north area) to help delineate subtle faulting or other reservoir development trends that could impact the length and direction of a horizontal well in sec. 20, T. 22 N., R. 4 E.

Petrographical Evaluations

Luff Exploration Co. will drill a Red River replacement well in sec. 17, T. 26 N., R. 58 E. (Richland County, Mont.) in early summer and plans to obtain a core from the Ratcliffe in this well.

Petrographical evaluations of the Ratcliffe and Red River have been resumed through Hendricks and Associates, Englewood, Colo. Completion of the petrography report is anticipated for June 1996.

References

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INTEGRATED APPROACH TOWARD THE APPLICATION OF HORIZONTAL WELLS TO IMPROVE WATERFLOODING PERFORMANCE

Contract No. DE-FC22-93BC14951

University of Tulsa
Tulsa, Okla.

Contract Date: Jan. 1, 1993
Anticipated Completion: Dec. 31, 1996
Government Award: $250,973

Principal Investigator:
Balmohan G. Kelkar

Project Manager:
Rhonda Lindsey
Bartlesville Project Office

Reporting Period : Jan. 1–Mar. 31, 1996

Objective

The overall objective of the proposed project is to improve secondary recovery performance of a marginal oil field through the use of an appropriate reservoir management plan. An integrated approach will be used for the selection of a plan based on a detailed reservoir description. With the use of this method, a 2 to 5% recovery of the original oil in place is expected. This should extend the life of the reservoir by at least 10 yr.

Summary of Technical Progress

During the last three months, implementation of the reservoir management plan in the Self Unit continued. Over this period, production from the unit increased up to 50 bbl/d (over 200% increase in the production). On the basis of the success so far, the other wells will be recompleted by the end of summer. For Stage II of the project, the scope of the project is being expanded. Instead of concentrating only on Tract 7, all the areas currently operated by Uplands Resources will be evaluated to determine the best location for either a multilateral or a horizontal well. The geological mapping is almost complete, and the geostatistical description and the flow simulation should start in early summer. Although not part of this project, a three-dimensional (3-D) seismic survey is being conducted on the Glenn Pool field. This should provide a better evaluation of the channel sand structure.

Project Monitoring

Last summer, implementation of the reservoir management plan in the Self Unit began. Last quarter, after the evaluation of each individual well, electrical submersible pumps were installed to produce three wells; this improved production from the field significantly. Over the last three months, the average daily production has been approximately 50 bbl/d. Compared to a baseline production of 13 bbl/d before the implementation, this is more than a 200% increase in production. On the basis of the current evaluation of the flow simulation results, the production from the unit should reach between 100 and 120 bbl/day once the implementation is complete.

Part of the reservoir management plan is to increase the water injection rate. The injection pump was installed, and the piping to bring the water from the Arkansas River was completed.

Geological Mapping

During the first quarter of 1996, geology activities of the Glenn Pool project included continuation of Tract 7 study, evaluation of Tract 16, and field scale correlation.

Tract 7 Study

Tract 7 study focused on the revision of net sand isopach and facies maps for each discrete genetic interval (DGI) constructed for the Tract 7 and adjacent area (1.6 square miles) in the last quarter of 1995. This revision became necessary after the acquisition of additional well data. Also, insights into the reservoir architecture of the Bartlesville sandstone gained from recent outcrop studies have greatly benefited this revision. In this version of facies architecture reconstruction, the Bartlesville sandstone (especially for DGIs A to C) is less layer-cake than earlier believed. As a result of this observation, a thick and blocky sandstone within the top part of the Bartlesville sandstone is more likely to be placed into one DGI than be divided into more than one DGI, which will result in DGIs A to C being more channelized than in the earlier interpretation.

The outcrop study has resulted in the recognition of a new facies for DGI F sandstone (about 40 to 50 ft thick). Although the facies interpretation of DGIs A to E is kept unchanged, DGI F is reinterpreted as braided-stream deposits. Facies interpretation for DGIs G and H cannot be done until the core study for these two intervals is complete.

Figures 1 to 4 show, as examples, the net sand isopach and facies maps for DGIs A, D, G, and H.

Tract 16 Evaluation

Tract 16, an 80-acre unit located immediately north of Self Unit, is being evaluated for horizontal drilling; however, the available development history record is not complete. A data survey has shown that at least 28 wells (maybe more) have been drilled in this unit (Fig. 5). Of these wells, only 3 were logged, 9 wells show limited completion information, and the remaining 16 wells have no data. Currently all of the wells are inactive.

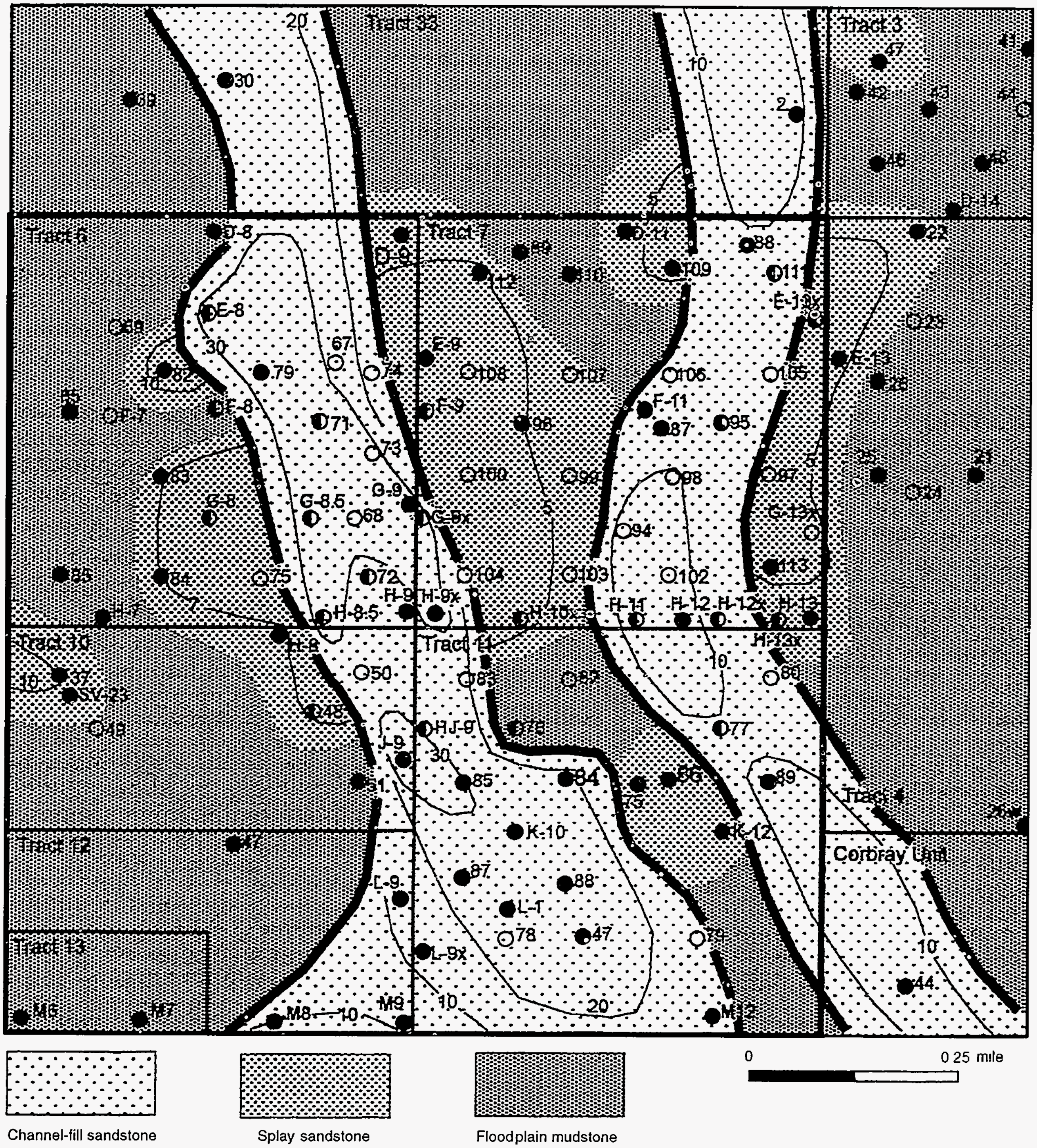


Fig. 1 Net sand isopach and facies map, DGI A (Tract 7 and adjacent area).

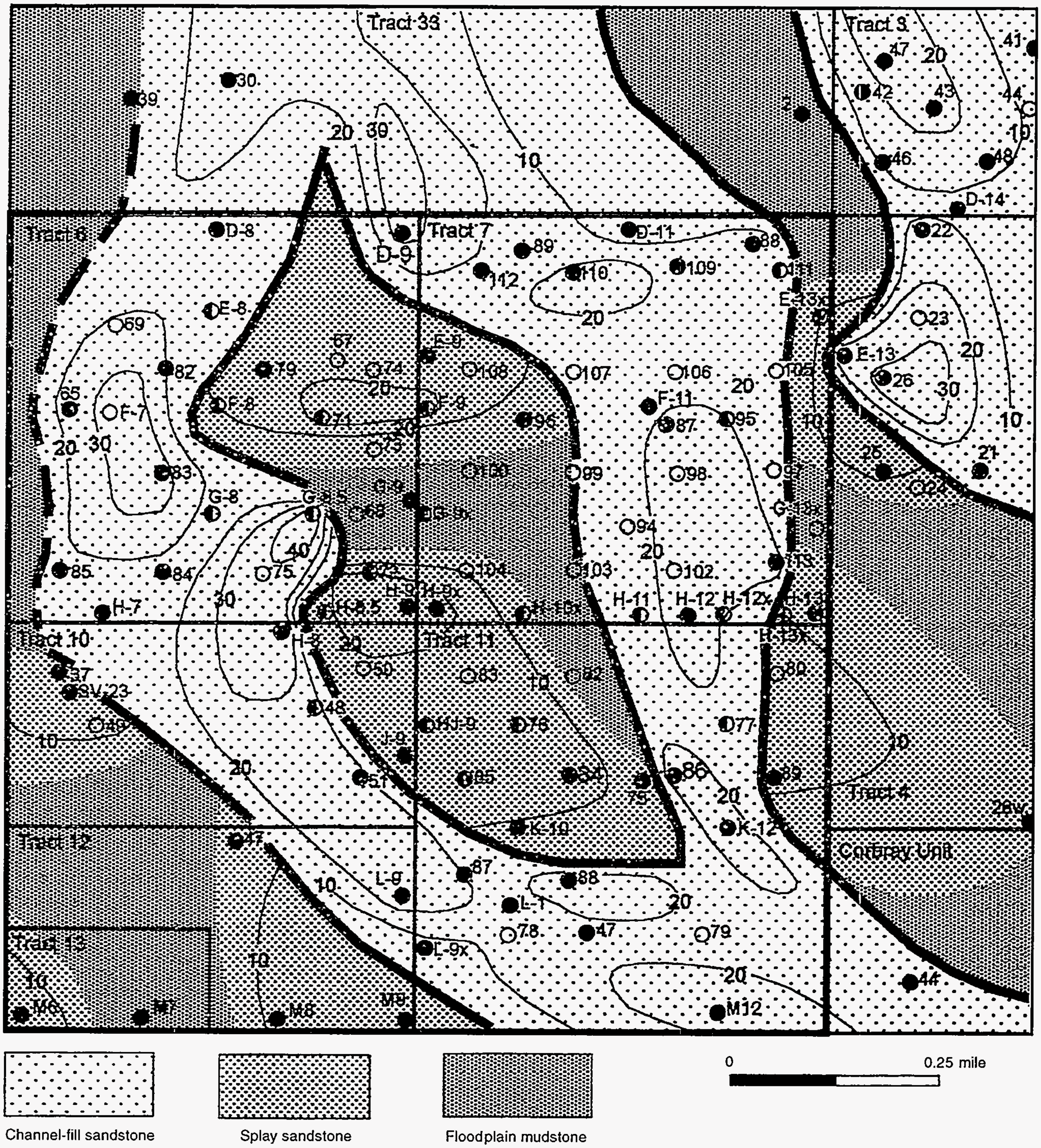


Fig. 2 Net sand isopach and facies map, DGI D (Tract 7 and adjacent area).

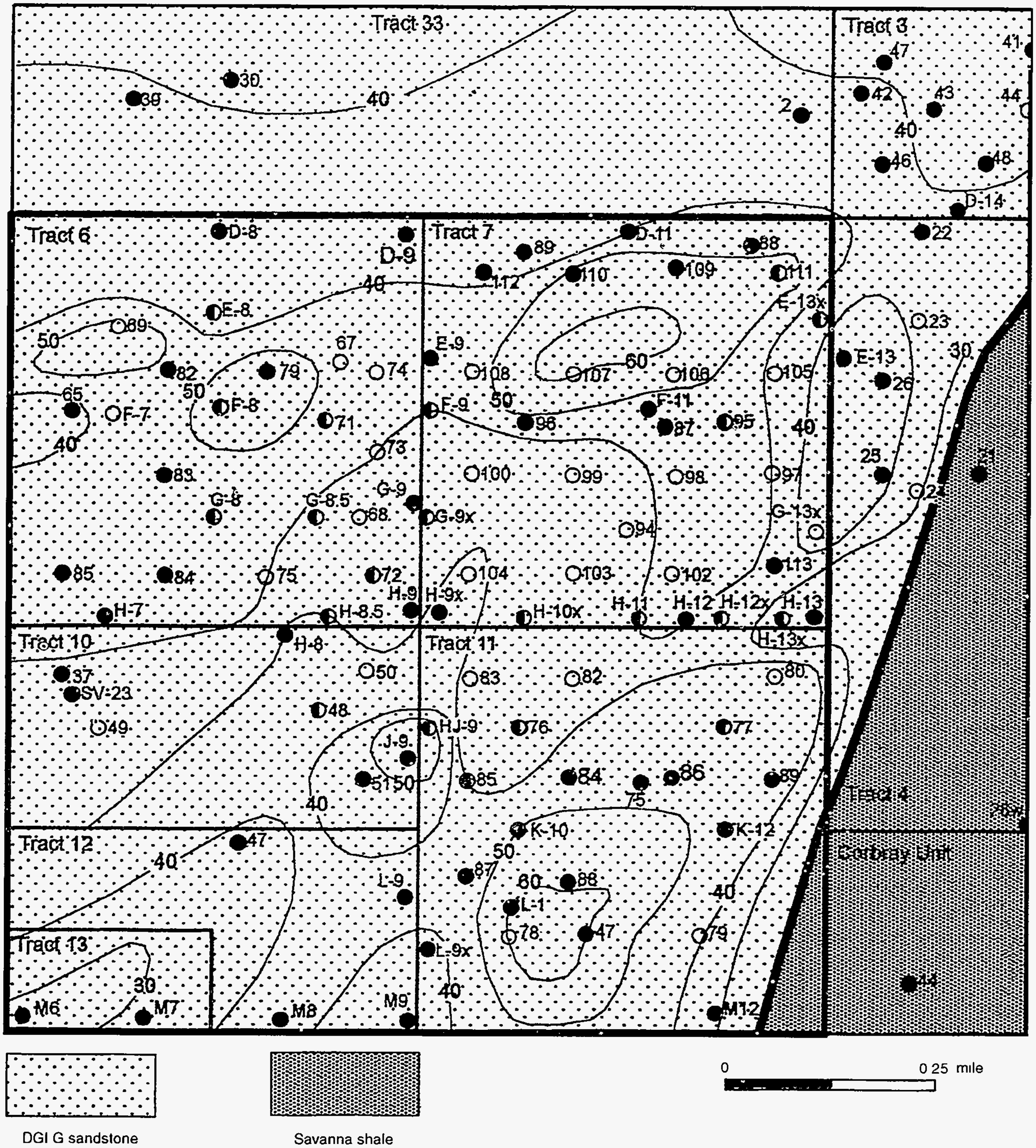


Fig. 3 Net sand isopach and facies map, DGI G (Tract 7 and adjacent area).

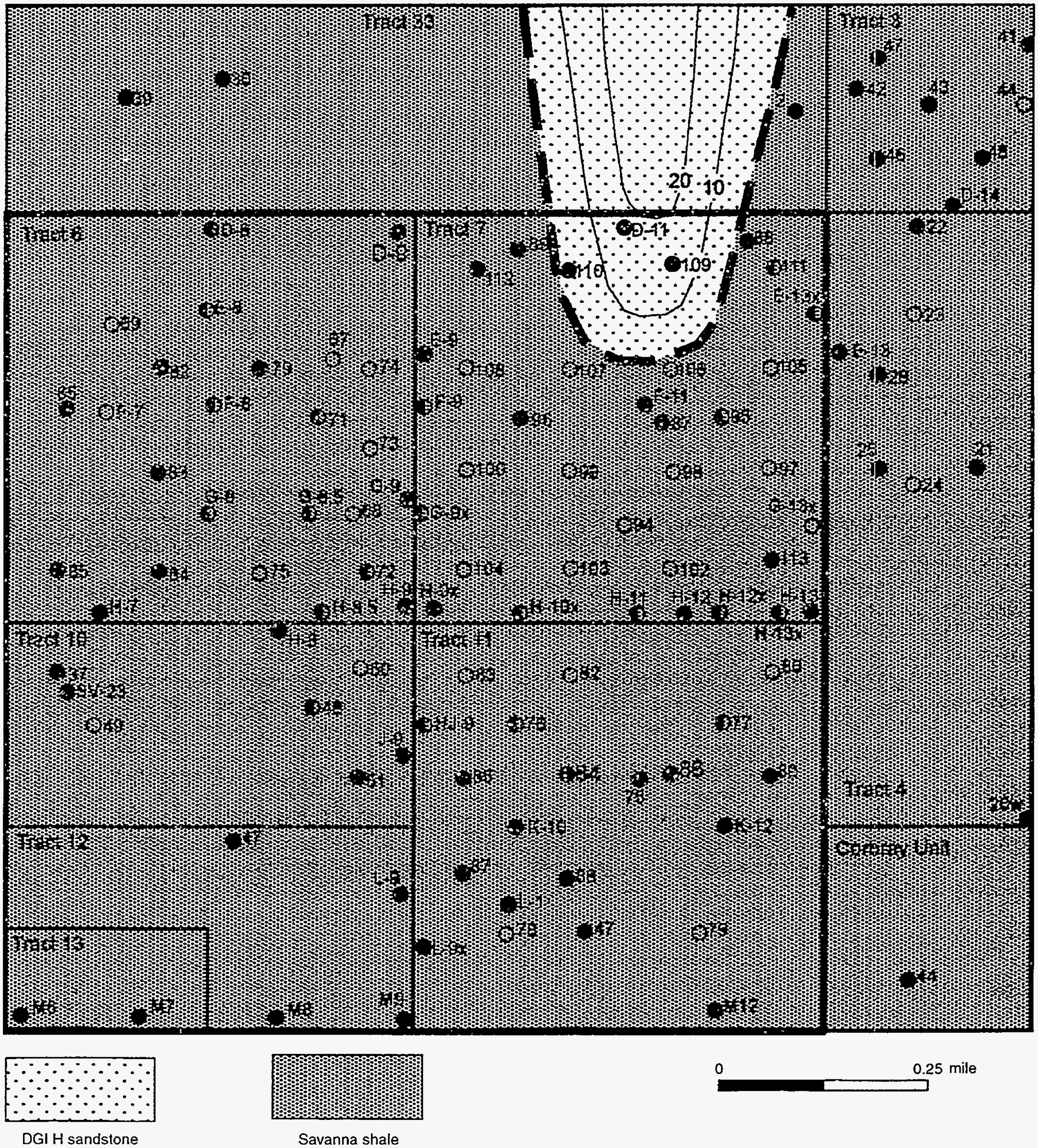


Fig. 4 Net sand isopach and facies map, DGI H (Tract 7 and adjacent area).

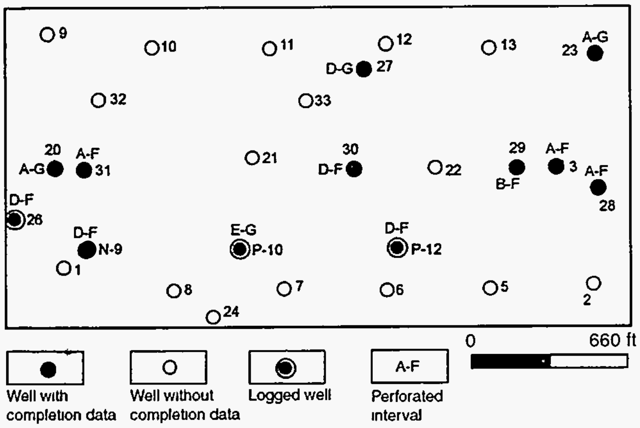


Fig. 5 Well location map for tract 16, 21–17 N., 12 E. (Note: There may be some other wells not shown on this map; i.e., Nos. 4, 14, 15, 16, . . . , etc.)

On the basis of the limited data available, initial geological analysis shows that DGI G and H sandstones are absent in the southern two-thirds of the unit. DGIs A to C have the most likely potential for further oil recovery.

Field-Scale Correlation

Field-scale correlation is being performed to broaden the understanding of larger scale variations of Glenn sandstone and selecting a proper unit for horizontal drilling.

Detailed correlation to the DGI level is being conducted over an area of about 25 square miles, which covers the entire southern part of Glenn Pool field, including all Uplands acreage and some immediately adjacent acreage. A total of 350 logs have been collected within the area. Correlation of these logs is approaching completion, which shows that DGIs G and H are not so extensive as originally thought and the Bartlesville sandstone thickens at the expense of the underlying Savanna shale. Cross sections, structure maps, and sandstone distribution maps for each DGI are being constructed to assist in the selection of a proper location for horizontal drilling.

Geophysical Interpretation

3-D Survey

Acquisition has been completed on the first square mile of the 3-D seismic survey. The acquisition team has delivered the field data, notes, and location map to Mercury International Tech for processing. The first task of converting the survey data into digital form is partly complete. From the work done so far, it is clear that the rest of the survey (10 square miles) must have digital positioning data at acquisition time. Processing for the test square mile will require two to three weeks.

Anisotropy

Work continues on the incorporation of anisotropy into a seismic ray-tracing computer program. This will provide a general tool for simulating, migrating, and tomographically inverting seismic data.

Engineering Interpretation

Data are being collected on production and well completion from the property operated by Uplands Resources. The data will be transformed into a database that can be easily accessed for further processing. Once all the data are collected, the collected data will be compared with the geological map to evaluate which wells are completed in which geological DGI. This should help identify potential areas with limited completions. The future work will include completing the data collection followed by a geostatistical description of the geological facies and the petrophysical properties.

Technology Transfer Activities

On the basis of the results obtained during Stage I of the project, several presentations have been made to report the progress. Researchers here participated in the Traveling Workshop Series, organized by the Petroleum Technology Transfer Council, which demonstrated the success of various Class I projects to independent operators in six cities. The response from small operators was very positive.

APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT AND RESERVOIR CHARACTERIZATION TO OPTIMIZE INFILL DRILLING

Contract No. DE-FC22-94BC14989

Fina Oil and Chemical Company
Midland, Tex.

Contract Date: June 13, 1994
Anticipated Completion: June 12, 1999
Government Award: $1,174,264

Principal Investigator:
P. K. Pande

Project Manager:
Rhonda Lindsey
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this project is to demonstrate the application of advanced secondary recovery technologies to the remedy of producibility problems in a typical shallow-shelf carbonate (SSC) reservoir of the Permian Basin, Texas. The technologies to be demonstrated are (1) development of an integrated reservoir description created with the use of reservoir characterization and reservoir management activities and integration and modeling of the data from three-dimensional (3-D) simulation, (2) development of an integrated reservoir management plan through optimization of completion and stimulation practices and reservoir surveillance, and (3) field demonstration of the geologically targeted infill drilling and waterflood program.

Summary of Technical Progress

Project Management and Administration

The emphasis during the past quarter was on development of the field demonstration recommendation and submission of the Continuation Application. Assimilation of all the reservoir characterization and performance analysis data with the simulation and geostatistics was conducted to determine the specific well locations for the field demonstration. Necessary preparations to implement the field demonstration also were completed.

Project Status

This project has used a multidisciplinary approach employing geology, geophysics, and engineering to conduct advanced reservoir characterization and management activities to design and implement an optimized infill drilling program at the North Robertson Unit (NRU). The activities during the first Budget Period, which is now complete, consisted of development of an integrated reservoir description from geological, engineering, and geostatistical studies and use of this description for reservoir flow simulation. Specific reservoir management activities have been identified and tested. The geologically targeted infill drilling program to be implemented during Budget Period II is a result of this work.

The overall thrust of this project has been geologically targeted infill drilling. Specifically, in Budget Period I, it was shown that it is possible to optimize economics for each and every new well in an infill drilling program. Blanket drilling in SSC reservoirs is neither prudent nor warranted with the modern reservoir characterization tools and techniques available to operators. The key is reservoir characterization and how it can help optimize and maximize recovery economics.

Project Continuation

During Budget Period II, 18 new infill wells, comprised of producers and injectors, will be drilled and completed. These wells are located in areas of the unit that appear to have good 10-acre infill potential (secs. 362, 329, and 327) as shown in Fig. 1.

The drilling of the 18 wells in the field demonstration will be implemented in a two-phase program which will consist of 11 wells in phase I followed by 7 wells in phase II. The phased implementation will allow flexibility in geologically targeting the final 7 wells in the field demonstration on the basis of performance and data obtained from the first 11 wells. The specific areas in which the phase I wells will be drilled are shown in Figs. 2 and 3. The flexibility and options available to drill the final 7 wells in secs. 329 and 327 are shown in Fig. 3. The development in sec. 362 consists of only 1 well to be drilled during phase I.

Analysis indicates that this project will recover approximately 2.2 million bbl of additional oil over a 20-yr period (see Table 1). These reserves and associated economics are sufficient to warrant implementation of the field demonstration during Budget Period II.

All the information from the geological, engineering, and reservoir performance analyses was used to geologically target the field demonstration well locations. Flow simulation is a good tool for targeting wells, but like any tool its limitations as well as strong points must be considered. Constructive discussion of the simulation studies and their input parameters was a high priority for the project team. Significant judgment using all the collective knowledge was applied to the final decisions for the field demonstration plan.

For SSC reservoirs, reservoir heterogeneity and compartmentalization is a day-to-day reality that impacts operators' field operations and subsequent well performance and may result in "untapped" oil. Researchers here have focused on the use of reservoir characterization tools and techniques to

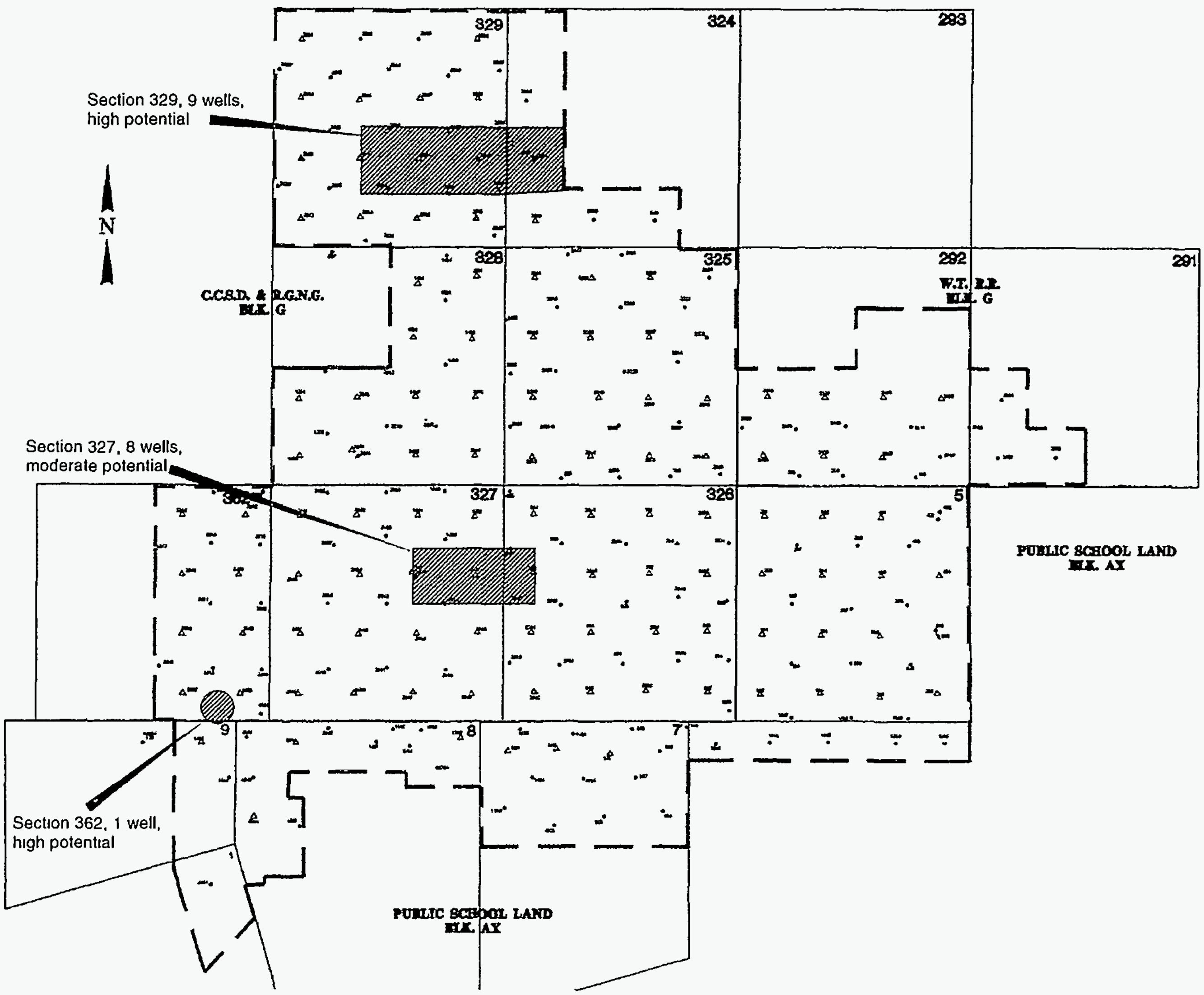


Fig. 1 Field demonstration areas with geologically targeted infill drilling (total of 18 wells) in Budget Period II, North Robertson Unit, Gaines County, Tex.

better deal with this producibility problem. With respect to reservoir simulation, especially deterministic modeling, which cannot capture this heterogeneity and compartmentalization, results from these conventional simulations predict more acceleration than additional recovery which may actually exist and be closer to "reality." These efforts in geostatistical reservoir description and flow simulation can improve on the shortcomings of conventional simulation. The validation exercise in Budget Period II will allow determination of the value of geostatistics in quantifying future reservoir performance.

Technology Transfer

Technology transfer activities for the project this quarter included a presentation to the Permian Basin Section of the Society of Petroleum Engineers. This paper, "Reservoir Characterization and Management — A Synergistic Approach To Development Optimization and Enhancing Value," was given on February 21, 1996, in Midland, Tex.

Two technology transfer workshops are scheduled for next quarter.

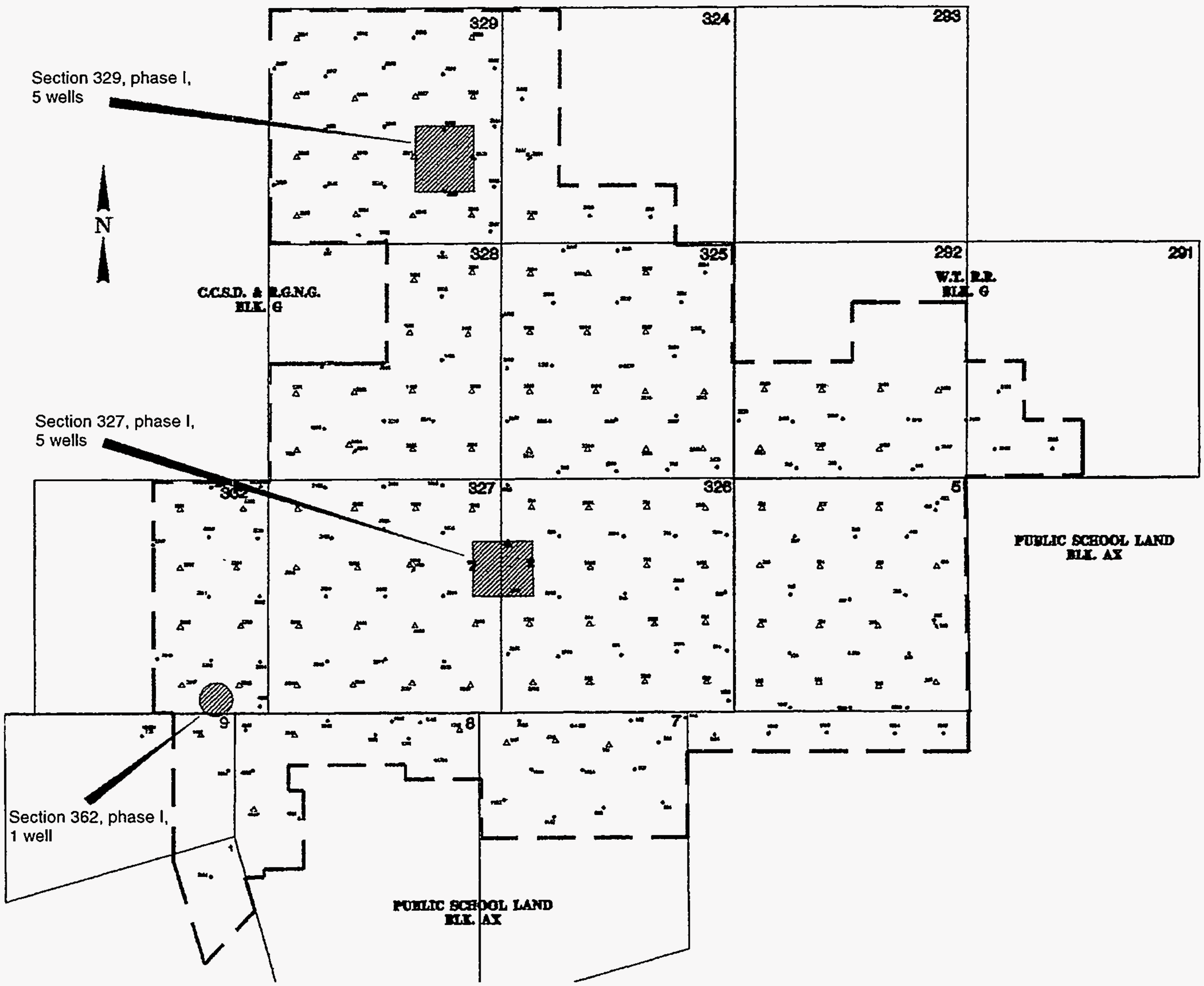


Fig. 2 Development areas with phase I drilling (total of 11 wells) in Budget Period II, North Robertson Unit, Gaines County, Tex.

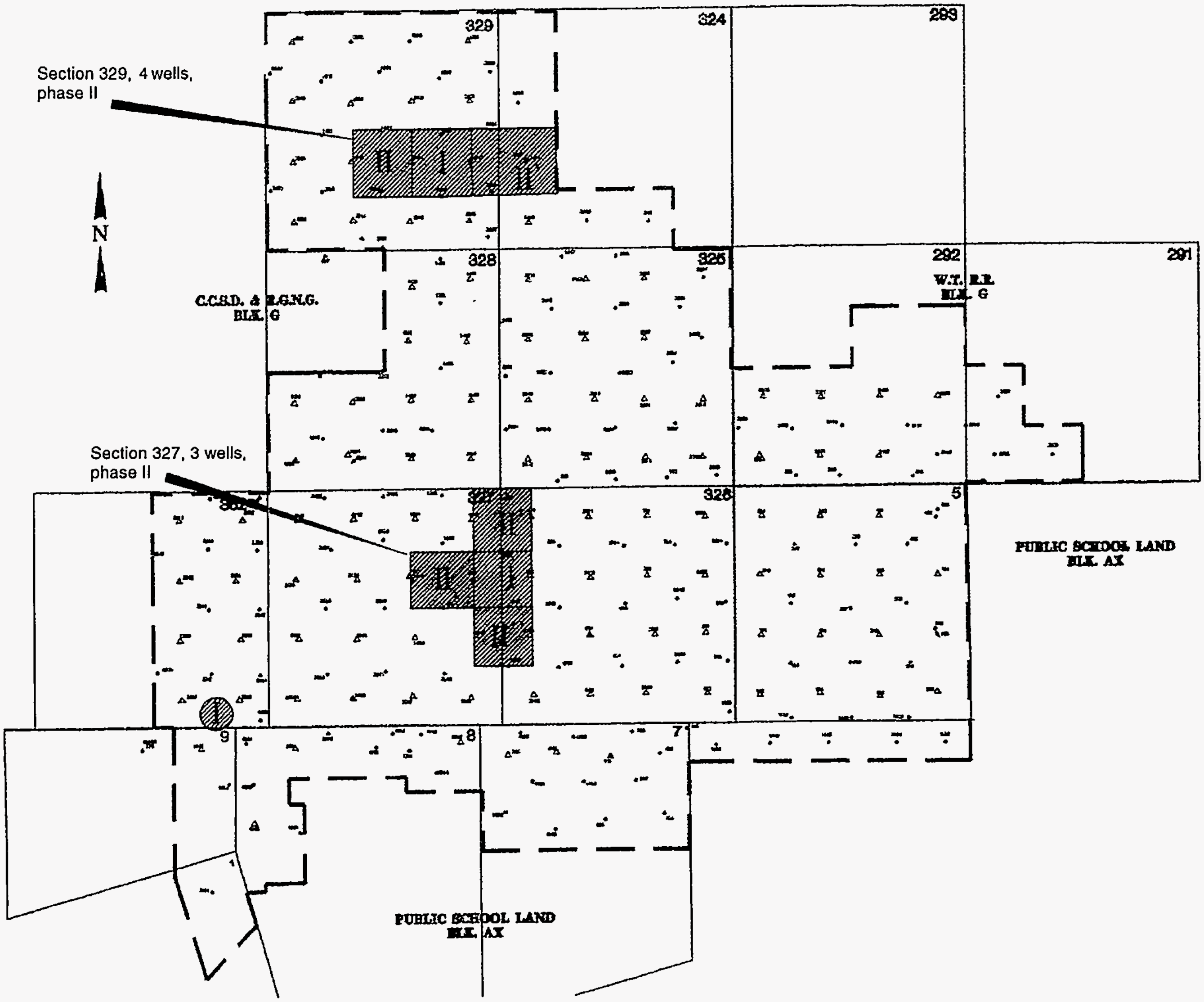


Fig. 3 Potential development areas for phase I drilling (11 wells) and phase II drilling (7 wells) in Budget Period II, North Robertson Unit, Gaines County, Tex.

TABLE 1

Reserves Expected in Each Area of the Field Demonstration

Area	Total No. wells, phases I and II	Estimated reserves, MBO	
		Per well	For area
High potential areas:			
Section 362	1	150	150
Section 329	9	130	1,170
Moderate potential area:			
Section 327	8	115	920
Total	18	124	2,240

IMPROVED OIL RECOVERY IN MISSISSIPPIAN CARBONATE RESERVOIRS OF KANSAS—NEAR TERM—CLASS II

Contract No. DE-FC22-94BC14987

University of Kansas
Lawrence, Kans.

Contract Date: Sept. 18, 1994
Anticipated Completion: Sept. 18, 1998
Government Award: $3,169,252

Principal Investigators:
Timothy R. Carr
Don W. Green
G. Paul Willhite

Project Manager:
Chandra Nautiyal
Bartlesville Project Office

Reporting Period: Jan.1–Mar. 31, 1996

Objective

The objective of this project is to demonstrate incremental reserves from Osagian and Meramecian (Mississippian) dolomite reservoirs in western Kansas through application of reservoir characterization to identify areas of unrecovered mobile oil. The project addresses producibility problems in two fields: specific reservoirs target the Schaben field in Ness County, Kans., and the Bindley field in Hodgeman County, Kans. The producibility problems to be addressed include inadequate reservoir characterization, drilling and completion design problems, and nonoptimum recovery efficiency. The results of this project will be disseminated through various technology transfer activities.

Summary of Technical Progress

Acquisition and Consolidation of Available Data

Acquisition and consolidation of existing geologic, digital log, and production data are complete. After protracted permitting problems, the third and final new well (2 Lyle Schaben "P," sec. 31, T. 19 S., R. 21 W.) was successfully drilled, cored, logged, and completed (Feb. 23, 1996). The Schaben core is being described and sampled for minipermeameter, thin-section, and nuclear magnetic resonance (NMR) analyses. The results of the NMR and capillary pressure analyses indicate that the dolomitic reservoir units have a bimodal distribution of porosity. On the basis of thin-section analysis, the two classes of porosity consist of large moldic pores connected by intracrystalline porosity.

This task is complete except for the ongoing addition of production data from the demonstration site and the results of the core analyses from the final new well.

Reservoir Characterization

A geologic reservoir characterization for Schaben field has been prepared for an initial reservoir simulation. When the first pass reservoir simulation is complete, the results will be evaluated and appropriate modifications made to the geologic model.

Analysis of data from the remaining new well along with development of a descriptive reservoir model will continue. Engineering analysis and initial simulation efforts are under way and results should be available during the coming quarter.

Work is under way to evaluate the Mississippian production in Kansas (including production from the Schaben demonstration site) in the context of production from the Mississippian reservoirs of the northern Williston Basin, Saskatchewan, Canada, where horizontal drilling in known fields has been successful.

Technology Transfer

Presentations at professional meetings have been well received (Platform Carbonates Workshop in Norman, Okla., in March and SIPES National Meeting in Dallas, Tex., in March).

Work will continue with Kansas operators on application of the technologies developed as part of the Class II project. Access to the digital data and results from the project are provided through an online (Internet) accessible format. The uniform resource locator for the Schaben home page is http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html.

POSTWATERFLOOD CO_2 MISCIBLE FLOOD IN LIGHT OIL FLUVIAL-DOMINATED DELTAIC RESERVOIRS

Contract No. DE-FC22-93BC14960

Texaco Exploration and Production, Inc.
New Orleans, La.

Contract Date: June 1, 1993
Anticipated Completion: Dec. 31, 1997
Government Award: $995,000

Principal Investigator:
Sami Bou-Mikael

Project Manager:
Chandra Nautiyal
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The overall objective of this project is to integrate research on petroleum reservoir characterization and process monitoring funded by the U.S. Department of Energy (DOE). Specific objectives this quarter include:

- Decide on continuing CO_2 purchases.
- Complete the reservoir model.
- Continue to monitor and optimize reservoir performance.

Summary of Technical Progress

CO_2 Purchases

Texaco terminated the CO_2 purchase agreement with Cardox because of the decline in production during 1995 and after exploring various alternatives to restore production from the project. New purchases of CO_2 were not necessary because it did not contribute to the recovery of new reserves from the project, and the stored CO_2 in the reservoir was sufficient to recover the remaining reserves through recycling. The current purchased CO_2 utilization factor is, in fact, higher than the originally estimated (2.8 mcf/bbl oil vs. 2.5 mcf/bbl oil). This evaluation was based on performance predictions by a compositional reservoir model built by Texaco and the overall project economics. The decision was communicated in a timely manner to DOE to obtain its support.

Reservoir Model

Texaco built a compositional model to evaluate the project performance and improve the decision-making process for project operations. The model included history matching of primary and secondary production and early CO_2 flooding in addition to various production runs.

The reservoir model (COMP III by SSI) integrated the results of the geologic model to improve the reservoir description. The spontaneous potential curves from the well logs were used to determine the shale content and derive the shale-corrected porosity. The porosity was used to calculate the permeability based on a porosity–permeability transform. A 4-layer model that better represented the heterogeneity of the reservoir and provided a flow path for the CO_2 to break through into the upper portion of the reservoir was used. It also provided a more accurate view of the areal extent of the reservoir by eliminating the area to the south of the reservoir where the Kuhn No. 6 well is located and reduced the total area of the reservoir by about 31% because of a localized shale-out.

Texaco modified the fault connections in the geologic model to isolate the main fault block and used the model to perform a history match and make prediction runs. The emphasis was placed on obtaining a total fluid match as opposed to individual well matches. The individual well performance was improved by producing the wells out to a point in time where the oil rates matched with the current values. This allowed the model to forecast production rates that are aligned with the current production rates. Prediction runs were made to evaluate the need for changing the injection pattern and to quantify the incremental oil that could be obtained with additional CO_2 purchases.

The results indicated that the new geologic description of the reservoir allows for an improved performance prediction and a reasonable estimate of oil recovery on the basis of two years of performance history of the CO_2 flood. It requires additional modification, however, to fully match well performance. The following highlights the model results:

- The original oil in place in the main fault block of the reservoir is 7 million bbl.
- The remaining recoverable oil reserves are in the range of 400,000 to 500,000 bbl.
- Incremental recovery from additional CO_2 purchases is limited. The cost of purchasing new CO_2 is not economically justifiable.

Monitoring and Optimizing Reservoir Performance

On the basis of results from the reservoir model, Texaco converted the Kuhn No. 42 well to a CO_2 injection well in order to improve reservoir sweep efficiency and sweep a new area of the reservoir that has not yet been affected by CO_2 injection. Currently the well is injecting CO_2 at a rate of 1823 thousand cubic feet per day. Wells Kuhn No. 17 and Margulina Area No. 1H are injecting water to maintain reservoir pressure and counterbalance the reservoir total fluid withdrawal. The Stark No. 10 well continues to inject CO_2 in the northern section of the reservoir. Production from well Kuhn No. 15R remains stable at an average rate of 125 barrels of oil per day, and it is anticipated that well Kuhn No. 15R will improve as the CO_2 injected in well Kuhn No. 42 reaches the well later this year. The second producing well, Kuhn No. 38, sanded up after producing from an open-hole gravel pack system for about 1 yr. The pressure in the reservoir is stable, based on the surface CO_2 injection pressure; however, the injection rate is slightly higher than the withdrawal rate, which should help increase the reservoir pressure and therefore improve the production rate. The well test results for March 1996 are shown in Table 1.

Technology Transfer

Texaco presented a paper at the April 1996 Society of Petroleum Engineers (SPE)/DOE Symposium on Improved Oil Recovery in Tulsa, Okla. The paper addressed the progress of the CO_2 flood at Port Neches and a new analytical method to select, design, and predict the performance of new CO_2 floods in sandstone reservoirs.

TABLE 1

Well Test Results, March 1996*

Well No.	BOPD	MCFGD	BWPD	Basic sediment and water, %	Pressure, psi	Choke
			Producing wells			
Kuhn No. 15R	137			82	840	22
Kuhn No. 38	24			90	1100	19
			Injection wells			
Kuhn No. 42		1823			1181	
Stark No. 10		1040			1182	
Kuhn No. 17			967		1780	
Margulina Area No. 1H			823		1780	

*BOPD, barrels of oil per day; MCFGD, thousand cubic feet of gas per day; BWPD, barrels of water per day.

REVITALIZING A MATURE OIL PLAY: STRATEGIES FOR FINDING AND PRODUCING UNRECOVERED OIL IN FRIO FLUVIAL–DELTAIC RESERVOIRS OF SOUTH TEXAS

Contract No. DE-FC22-93BC14959

University of Texas at Austin
Bureau of Economic Geology
Austin, Tex.

Contract Date: Oct. 21, 1992
Anticipated Completion: Aug. 31, 1996
Government Award: $817,911

Principal Investigators:
Noel Tyler
Raymond A. Levey

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

Project objectives are divided into three major phases. The first phase, reservoir selection and initial framework characterization, consisted of the initial tasks of screening fields within the play to select representative reservoirs that have a large remaining oil resource and are in danger of premature abandonment and performing initial characterization studies on selected reservoirs to identify the potential in untapped, incompletely drained, and new pool reservoirs. The second phase involved advanced characterization of selected reservoirs to delineate incremental resource opportunities. Subtasks included the volumetric assessments of untapped and incompletely drained oil and an analysis of specific targets for recompletion and strategic infill drilling. The third and final phase of the project consists of a series of tasks associated with documentation of the results of the second phase, technology transfer, and the extrapolation of specific results from reservoirs in this study to other heterogeneous fluvial–deltaic reservoirs within and beyond the Frio play in South Texas.

The goals of the industrial associates program that is the source of industry cofunding to this project are to develop an understanding of sandstone architecture and permeability structure in a spectrum of fluvial–deltaic reservoirs deposited in high- to low-accommodation settings and to translate this understanding into more realistic, geologically constrained reservoir models to maximize recovery of hydrocarbons.

Summary of Technical Progress

Project work during the first quarter of 1996 included tasks related to the transfer of technologies to industry. The two primary vehicles for transferring technologies evaluated in the Frio fluvial–deltaic sandstone play (Vicksburg Fault Zone) (Fig. 1) are a series of two short courses and a microcomputer-based geologic advisor software program. The first of the two short courses was given during the first quarter, and a preliminary version of the software was demonstrated to industry for feedback. The second short course is scheduled for the second quarter, and release of the software is planned for the third quarter. In addition, some technical work is ongoing to refine the interpretation of remaining hydrocarbons in the two study areas, which will provide additional supporting evidence of opportunities to field operators.

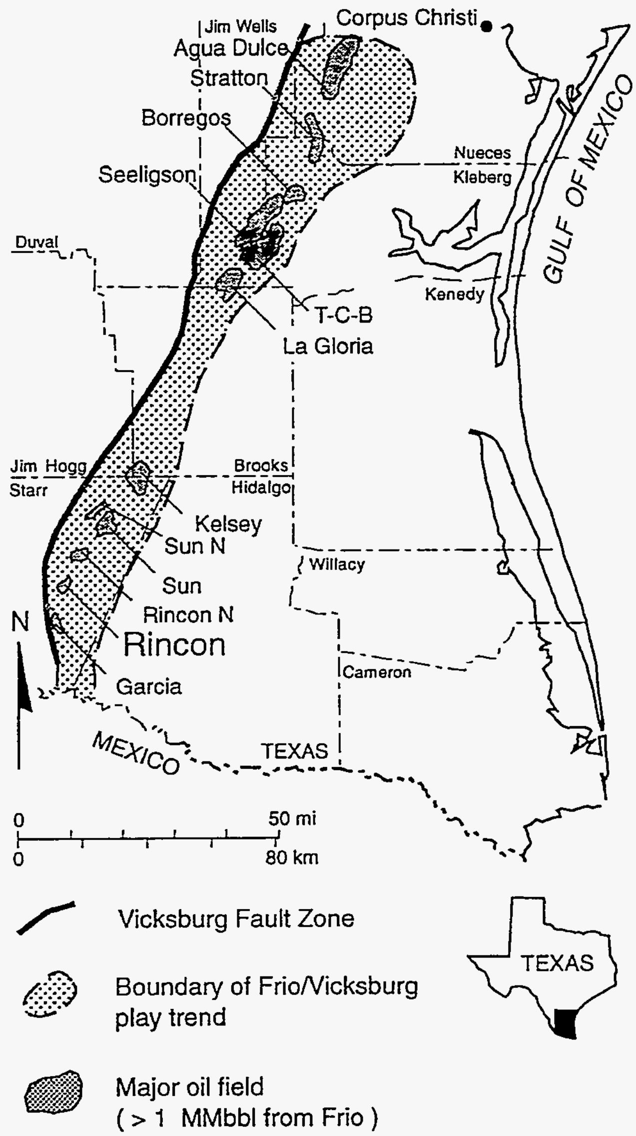


Fig. 1 **Map of south Texas showing location of fields within the Frio fluvial–deltaic sandstone play along the Vicksburg Fault Zone. (Modified from Galloway et al.[1] and Kosters et al.[2])**

In addition, technical work in the two fields selected for detailed study [Rincon field in Starr County, Tex., and Tijerina–Canales–Blucher (TCB) field in Jim Wells County, Tex.] is continuing in order to more clearly define reserve-growth opportunities for operators. In Rincon field, a three-dimensional (3-D) reservoir model is being constructed to more accurately calculate remaining volumes, and work during the first quarter focused on a sensitivity analysis of varying model parameters. In the TCB field, horizon-slice analysis of the 3-D seismic data volume has been done in an attempt to image lateral reservoir extent, which will help to refine net sandstone maps and more clearly identify compartment boundaries.

The Geologic Advisor

The Geologic Advisor software package is a technology transfer tool that has the potential of reaching a large audience. The program is being designed to provide operators with an illustrated microcomputer-based guide to the reservoir characterization process, which leads to the identification of reserve-growth potential. The Geologic Advisor has now reached the beta stage of development and is being demonstrated to reviewers, both at the Bureau of Economic Geology (BEG) and outside the university, for feedback. The screen design has been established and is considered readable and easy to use.

Continued Technical Support

Following the conclusion of second-phase tasks, technical efforts in reservoir characterization have continued in order to provide additional supporting evidence to operators of the validity and risks associated with specific reserve-growth opportunities. In Rincon field, this includes construction of a 3-D reservoir visualization model with initial work focusing on the sensitivity of the model to changing parameters. In the TCB field, continued technical work this quarter has been directed toward stratigraphic analysis of selected layers to aid in the definition of compartment boundaries.

Rincon Field

A 3-D reservoir visualization model was built to refine the understanding of the location and volume of remaining oil. The outcome of such a model is a consequence of the approach used to establish flow-unit geometries and extrapolate petrophysical characteristics from well locations. A sensitivity analysis was undertaken that considered the method of describing flow units that thin laterally (either proportionally or by onlap onto an underlying surface): whether a directional bias should be applied in the extrapolation of petrophysical characteristics, potentially reflecting a preferential directional fabric within the reservoir, and whether a facies template should be used, such that petrophysical characteristics are stochastically extrapolated within a deterministic framework established by geologic facies mapping (that is, values are extrapolated between two adjacent wells in a channel facies, but values from these wells are not used to extrapolate to a third adjoining well located in a floodplain facies).

Table 1 shows the results of the sensitivity analysis for five cases. On the basis of geological knowledge about the reservoir in question, case 1 is the most accurate but complex case, wherein layers are thinned proportionally and a facies template is used without any directional bias applied. Successive cases consider situations in which flow units are thinned by onlap and in which petrophysical characteristics are distributed with or without a facies template with directional bias either applied or not applied. The fifth and sixth columns of Table 1 show the resulting calculated original oil in place (OOIP) and the percent difference from the ideal case (case 1). The largest factor affecting the outcome seems to be the method used to describe the thinning of the flow units, perhaps because it so substantially affects reservoir volume. The difference between proportional thinning and onlap made a difference

TABLE 1

Results of a Sensitivity Analysis of the Rincon Field Reservoir Model

Experiment	Layer method	Directional bias	Facies template	OOIP,* STB	Percent change
Case 1	Proportional	No	Yes	10,392,900	–
Case 2	Onlap	No	Yes	8,231,690	–21
Case 3	Onlap	Yes	Yes	7,957,790	–23
Case 4	Onlap	Yes	No	7,662,200	–26
Case 5	Onlap	No	No	7,855,270	–24

*OOIP, original oil in place; STB, stock tank barrel.

of more than 20% in the calculated OOIP. With the use of a facies template, the accuracy of the calculation improved by 3% in cases in which directional bias was applied (case 3 vs. case 4) and in which it was not (case 2 vs. case 5). In this analysis, the application of directional biasing of petrophysical characteristics actually decreased the accuracy by 2% (case 2 vs. 3 and case 4 vs. 5). This may be a consequence of the complexly multidirectional nature of depositional trends in the fluvial (upper delta-plain) reservoir used in the analysis.

TCB Field

A reprocessed 3-D seismic data set donated by Mobil Exploration and Producing U.S. Inc. is being analyzed to better understand stratigraphic controls on reservoir compartments. Despite a relatively low useful frequency range of 10 to 50 Hz that limits vertical resolution, numerous stratigraphic features that affect reservoir geometry are visible in the data set. Seismic analysis has focused on an interval between the 13A and 21D horizons (Fig. 2) that is relatively unaffected by faulting. These strata are mostly upper delta-plain deposits of the middle Frio formation. Time–depth relationships have been established with the use of two checkshot surveys, seven synthetic seismograms constructed from acoustic and density logs, and a vertical seismic profile collected during reprocessing.

Thirteen key stratigraphic horizons have been picked within the data volume. Maps of two-way time and reflector amplitude constructed from these horizons and more than 50 maps derived from these key horizons are yielding additional information that allows us to refine facies and net sandstone maps constructed from well logs only [for example, a horizontal time slice from the 21B zone in the North-central part of the seismic data set (Fig. 3) shows an amplitude high that forms a channel-like feature in the shape of a flattened "S." A generalized version of the same feature is evident on a net sandstone map of the same geographic area and stratigraphic interval (Fig. 4). The greatly increased level of detail visible on the seismic image attests to the benefits of better lateral resolution in the seismic data set than in the well log data set. These horizon mapping techniques are being combined with other advanced seismic analysis tools, such as amplitude thickness mapping, to locate likely stratigraphic targets for enhanced hydrocarbon recovery.

Other Technology Transfer Activities

A manuscript was completed and preprints published to accompany a presentation to the Society of Petroleum Engineers/DOE Improved Oil Recovery Conference to be held April 22, 1996, in Tulsa, Okla.

Characterization of Heterogeneity Style and Permeability Structure in a Sequence Stratigraphic Framework in Fluvial–Deltaic Reservoirs (Matching Funds Source)

Because of the worldwide importance of resources in fluvial–deltaic reservoirs, a consortium of oil companies is funding research at BEG aimed at reservoir characterization of fluvial–deltaic depositional systems. The goals of this program are to develop an understanding of sandstone architecture and permeability structure in a spectrum of fluvial–deltaic reservoirs and to translate this understanding into more-realistic, geologically constrained reservoir models. The approach is to quantify the interrelationships among sequence stratigraphy, depositional architecture, diagenesis, and permeability structure through detailed outcrop characterization. This industrial associates program is the source of the 50% cofunding for BEG's Class I Oil Project.

The investigation of reservoir description and modeling problems continued. The goal of this task is to build descriptive and distinct spatial models for both seaward- and landward-stepping elements of the Upper Cretaceous Ferron sandstone, a fluvial–deltaic system deposited in a high-accommodation setting in Utah. The results will be used to quantify differences in recovery behavior between the two architectural styles.

During this quarter, tabular and gridded versions of the Ferron outcrop data were translated into formats that can be imported into the commercial flow simulator Eclipse. The geometric and petrophysical accuracy and consistency of these models are being verified. Each stratum in the outcrop image is translated to one or more simulation grid layers. All layers are divided into cells by intersecting this stratigraphic coordinate system with a series of evenly spaced vertical lines. The cell boundaries are then defined by the intersection of the vertical lines with stratigraphic surfaces. The (x,z) coordinates of these intersections are used to specify the "corner-point geometry" for the simulator. These corner points are also used to determine the cell center and to interpolate facies descriptions and petrophysical properties. The corner-point geometry and rock properties are written to large "include" files, which can be parsed by the commercial preprocessing, simulation, and visualization programs. Ultimately, this will facilitate dissemination of detailed architectural data from the Ferron outcrop study.

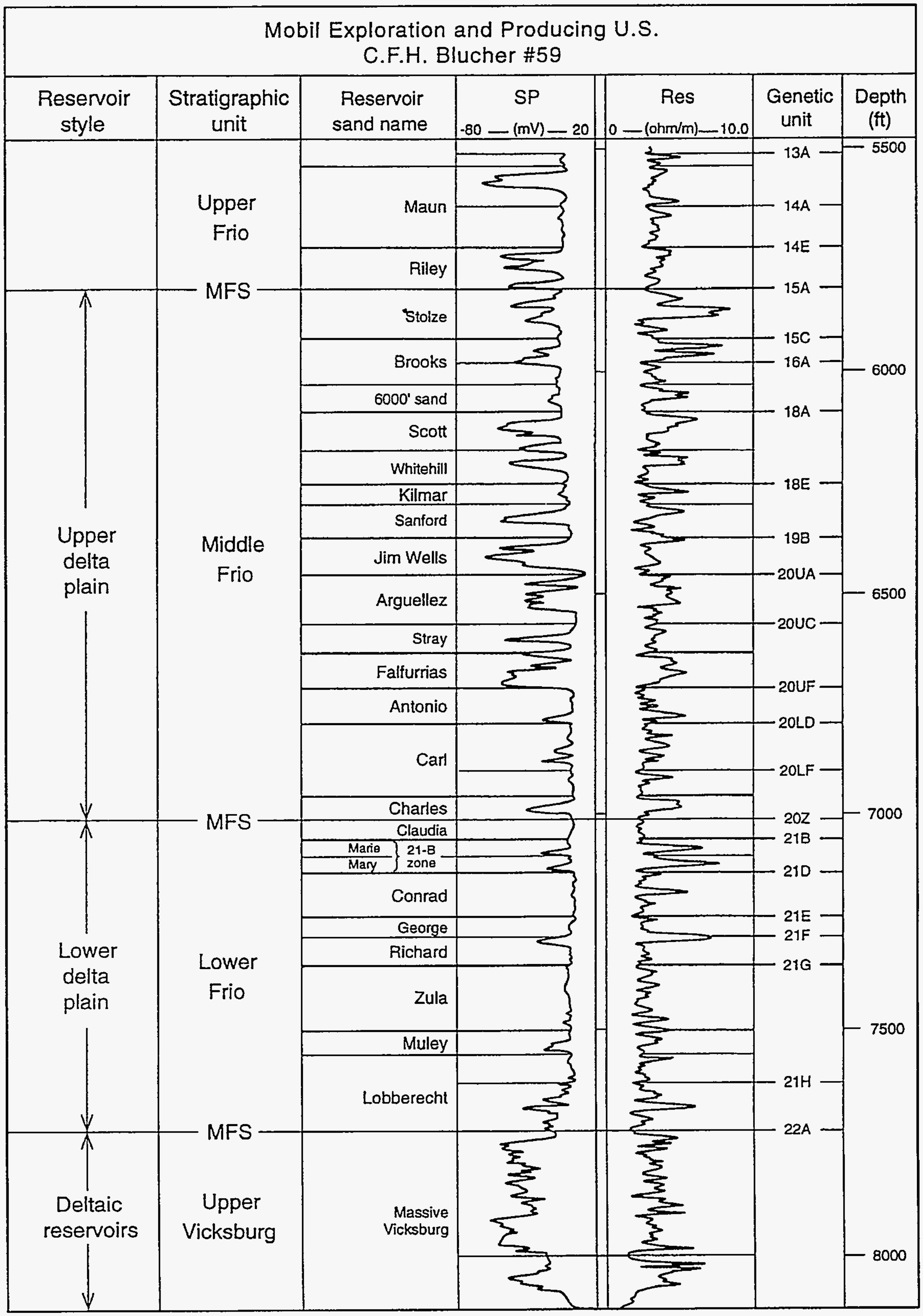


Fig. 2 Type log for the Tijerina–Canales–Blucher (TCB) field showing the relationship among formation, reservoir sandstone name, and genetic unit top markers.

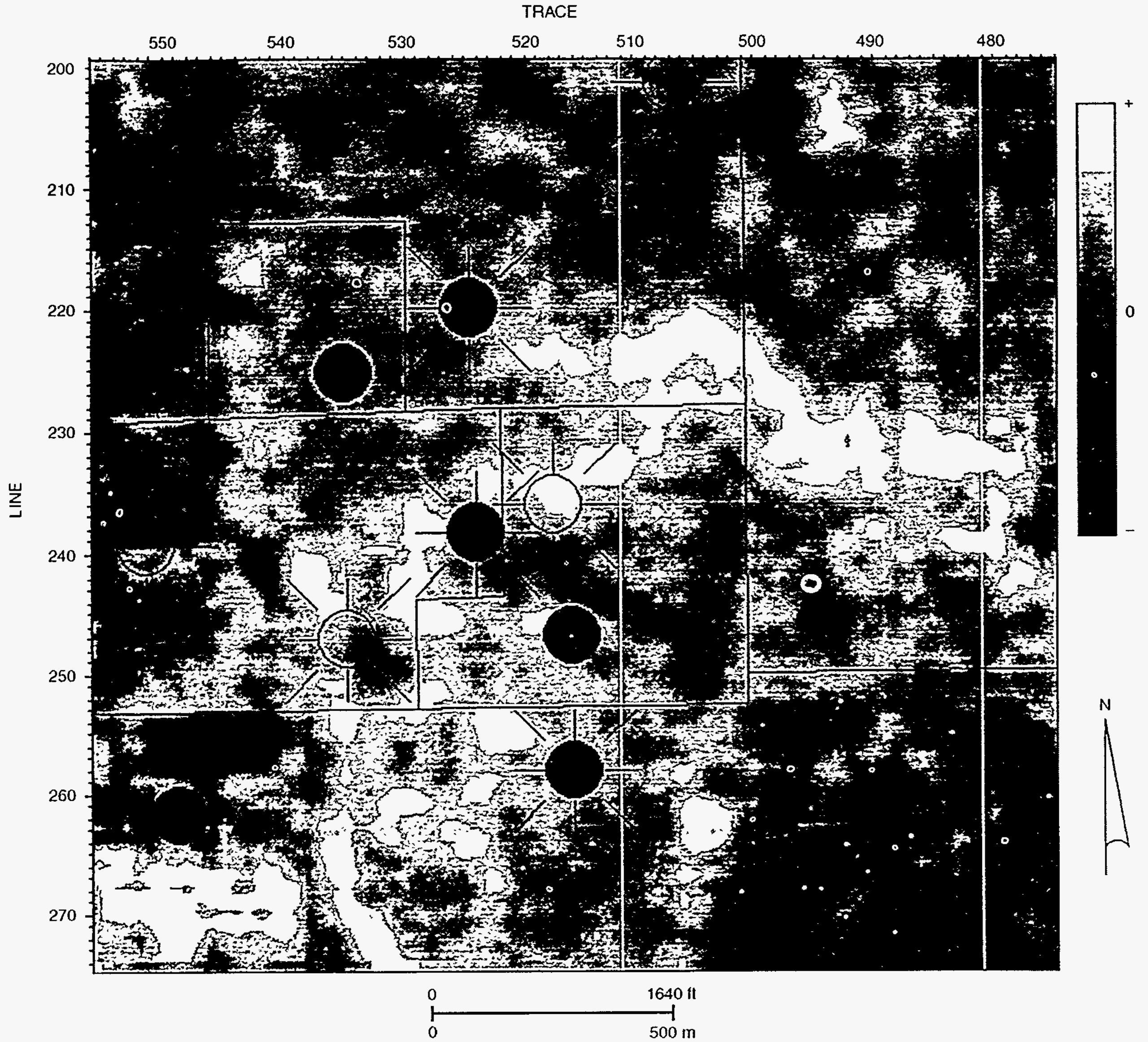


Fig. 3 Amplitude map for the genetic unit below the 21B marker with higher amplitudes (lighter colors) indicating greater sandstone volumes. (Figure 4 shows the corresponding net sandstone map drawn with the use of only well control.)

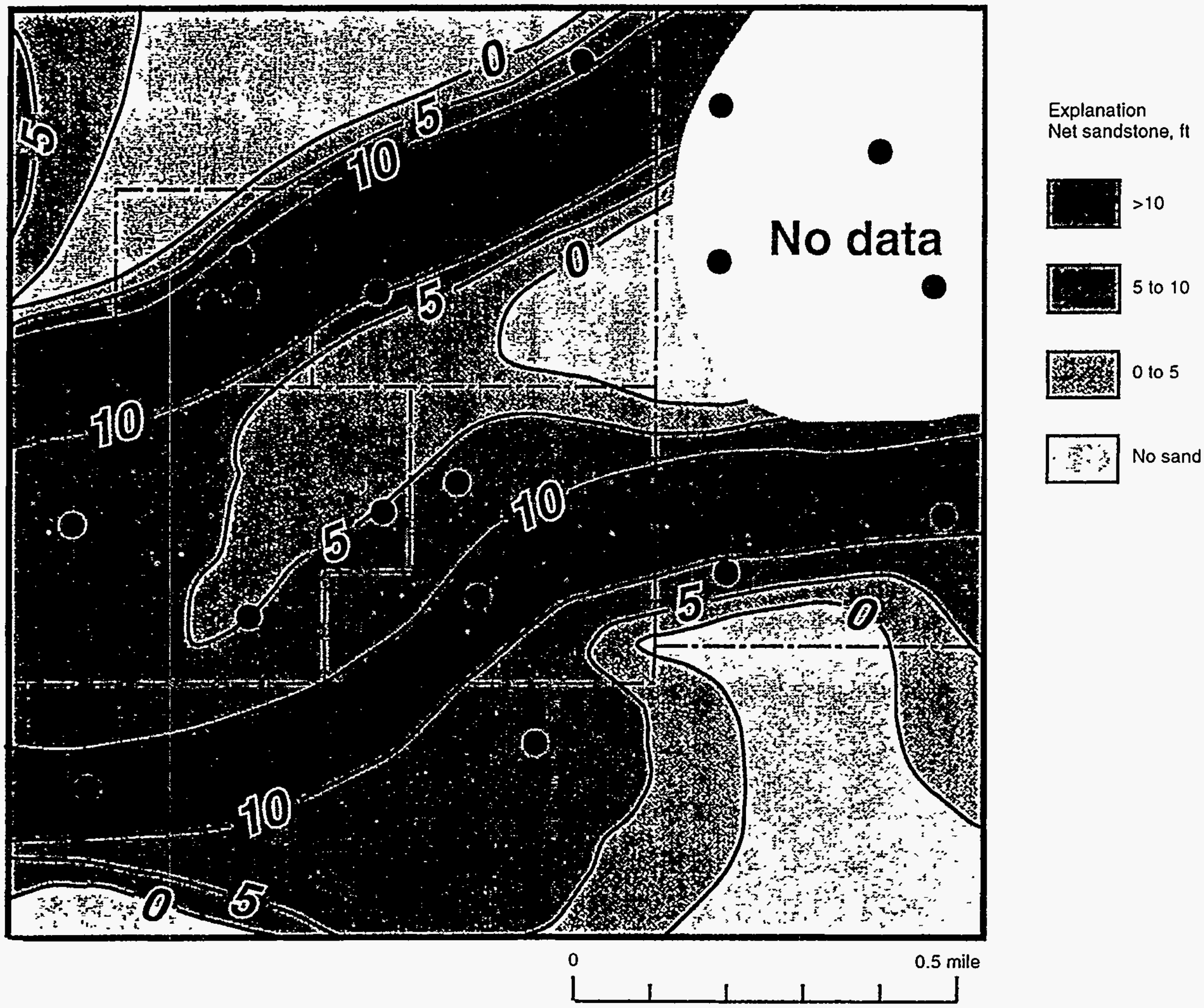


Fig. 4 Net sandstone map for the 21B-2 reservoir. Contoured with the use of only well data, this map suggests two separate, relatively straight channels with narrow to wide areas of levee or overbank. (The amplitude map that includes this interval is shown in Fig. 3.)

References

W. E. Galloway, T. E. Ewing, C. M. Garrett, N. Tyler, and D. G. Bebout, *Atlas of Major Texas Oil Reservoirs,* The University of Texas at Austin, Bureau of Economic Geology, 1983.

2. E. C. Kosters, D. G. Bebout, S. J. Seni, C. M. Garrett, Jr., L. F. Brown, H. S. Hamlin, S. P. Dutton, S. C. Ruppel, R. J. Finley, and N. Tyler, *Atlas of Major Texas Gas Reservoirs,* The University of Texas at Austin, Bureau of Economic Geology Special Publication, 1989.

FEASIBILITY OF OPTIMIZING RECOVERY AND RESERVES FROM A MATURE AND GEOLOGICALLY COMPLEX MULTIPLE TURBIDITE OFFSHORE CALIFORNIA RESERVOIR THROUGH THE DRILLING AND COMPLETION OF A TRILATERAL HORIZONTAL WELL

Contract No. DE-FC22-95BC14935

Pacific Operators Offshore, Inc.
Ventura, Calif.

Contract Date: Sept. 1, 1995
Anticipated Completion: Aug. 31, 1999
Government Award: $814,718
(Current year)

Principal Investigator:
Steven F. Coombs

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The main objective of this project is to devise an effective redevelopment strategy to combat producibility problems related to the Repetto turbidite sequences of the Carpinteria field. The lack of adequate reservoir characterization, high water-cut production, and scaling problems have contributed to the low productivity of the field.

Summary of Technical Progress

Production Data

During this reporting period, the production history database was carefully compared with historical hard-copy reports and the production history database available from the regulatory agency (the Minerals Management Service). Each of these databases contains a large number of monthly oil, gas, and water production values. In order to compare the two databases, a computer program was written to compare the data on a well-by-well and month-by-month basis. The differences were checked with the hard copy and corrections were made where appropriate.

Well Log Data

Further progress has been made on the well log database. The well log processing system being used for this task is Scientific Software's LOGCALC II running on a DEC Micro-VAX II system. The status of the well log database as of March 31, 1996, is shown in Table 1.

TABLE 1

Carpinteria Well Log Status (OCS Lease P-0166) as of Mar. 31, 1996

Work description	Percent complete
Wells with log traces in digital form	100
Directional survey data complete	100
Dipmeter or mapped dip data for TVT/TST* logs	100
Marker/zone defined, tops and bottoms	95
Log correction/normalization/manipulation	99
Porosity/saturation calculations	95
Core/log verification/modeling	65
Saturation/porosity/oil-in-place computer model	75
Output logs, TST and TVD* logs	90

*TVT, borehole televiewer; TST, formation saturation test; TVD, *true vertical depth.*

Well Testing

Well Test Data

During this period, all remaining pressure data for OCS lease P-0166 were analyzed. A total of 39 pressure-buildup tests have now been analyzed, including 17 drill stem tests (DSTs). The results of these DSTs are shown in Table 2. Results of analysis from DSTs 3, 4, and 5, which had surface flow rates, are believed to produce the most reliable permeability values for the subthrust G-7 and the suprathrust G-1 and F-1 layers, respectively, in the drainage areas encountered during the tests.

Pressure–Volume–Temperature (PVT) Data

Further analysis of PVT data resulted in the data shown in Table 3, which shows a comparison between the properties of the reservoir fluids. Figure 1 shows a linear relationship of methane content with saturation pressure of the reservoir fluids.

Reservoir Pressure

In addition to the static pressure data, a flowing bottomhole pressure database has been developed from fluid level measurements from the last 5 yr of operations. Figure 2 shows flowing bottomhole pressure vs. time.

Stratigraphy and Microlamination

All available conventional core analyses from whole core and sidewall plugs from wells shown in Table 4 have been digitized. These data will be used for the microlamination study. In addition, screen or sieve analysis, where available, will also be studied in detail. A general trend of east-to-west

TABLE 2

Analysis of Drill Stem Tests (DST)

Well No.	Fluid	Date	Type	Zones	Ref. depth	P, psig	Permeability (k), mD
CH-6	38 BOPD	4/26/67	DST 3	G-7ST	–4944	2243.5	k_o 1.43
	12 BWPD						k_w 0.11
CH-6	348 BOPD	4/29/67	DST 4	G-1	–3436	1594	45.9
CH-6	555 BOPD	4/30/67	DST 5	F-1	–2854	1277	386.5
A-1	60% oil	5/24/68	DST 1	G-6	–4254	1880	2.3
	40% water						2 FP 3.8
A-1	Water	5/25/68	DST 2	F-4	–3467	1548.5	81.2
A-1	90% oil	5/27/68	DST 3	F-4	–3467	1556	56.6
A-1	Water	5/28/68	DST 4	E-1	–2641	1200.9	42.3
A-1	Oil	6/2/68	DST 5	E-1	–2641	1193.5	110.8
A-2	Water	5/19/68	DST 1	F-4	–3496	1534	307
A-2	Oil	5/20/68	DST 2	F-1	–3170	1373	104.7
A-2	Oil	5/21/68	DST 3	E-2	–2785	1230	132.6
A-7	Oil	9/26/68	DST 1	F-1	–3077	1206	124.5
A-12	Oil	7/30/68	DST 1	G-7ST	–5120	2351	13.8
A-12	Oil	8/1/68	DST 2	G-6ST	–4829	2156	36
A-12	Gas	8/2/68	DST 3	G-5ST	–4741	–	0.3
B-2A	Oil	4/24/69	DST 1	G-5AST	–4818	2173	9.6
B-2A	Oil	4/25/69	DST 2	G-3B	–3485	1557	234

Note: Ref. depth, reference depth (depth where DST was conducted); P, reservoir pressure at reference depth obtained from the analysis of DST pressure data.

TABLE 3

Comparison Between Reservoir Fluids

No.	Type of sample	Formation	Temp., °F	P_b, psig	R_s, scf/STB @ P_b and reservoir temperature
1	Rec. well CH-6		110	1546	223
2	Rec. well No. 40	E-1 zone	124	1218	173
3	BH sample A-7	F zone	122	2155	336
4	BH sample B-2A	G-3A zone	126	1271	212
5	BH sample B-2A	G-5AST	145	974	273

Note: P_b, bubble point pressure of fluid sample; R_s, solution gas/oil ratio at specified pressure and temperature.

permeability decrease was observed from core data and analysis of initial oil production.

Reservoir Performance

Because of the heterogeneous nature of reservoir fluids in lease P-0166 and large contrasts in individual layer pressures caused by differential depletion, an effort to develop new methods for production allocation to individual layers with the use of commingled well production began. The allocated production data will be used to calculate initial oil in place in the three main sands as well as in the subthrust reservoirs.

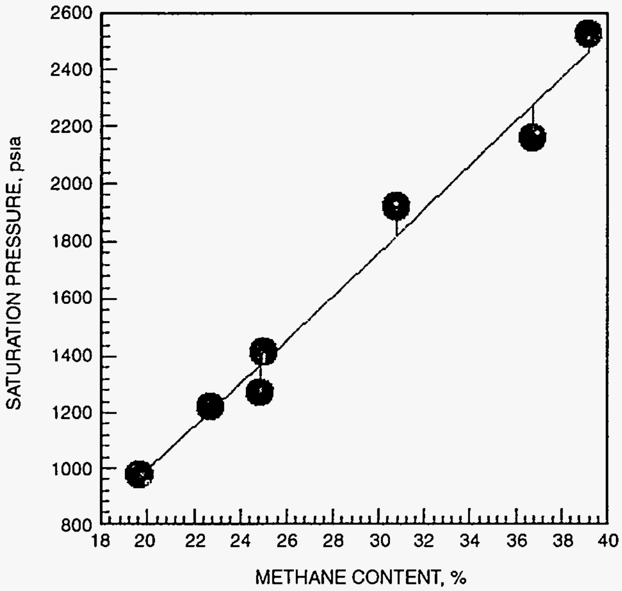


Fig. 1 Saturation pressure vs. methane content.

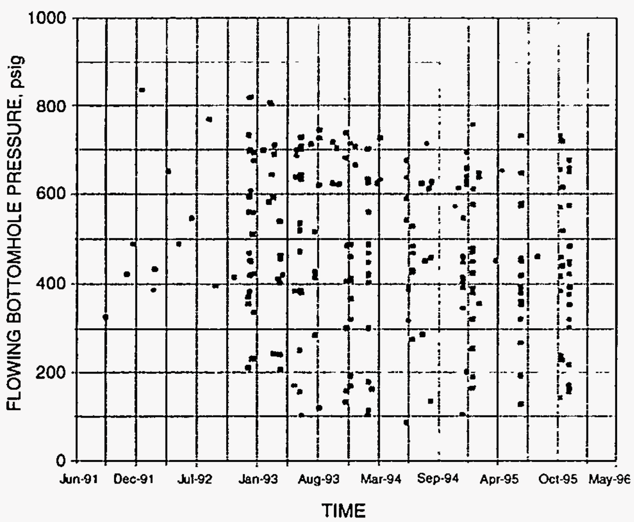


Fig. 2 Sand face pressure vs. time for OCS lease P-0166. Reservoir pressure at –3300 ft subsea.

TABLE 4

OCS Lease P-0166 Core Material

Date cored	Well	Zones cored
August 1968	A-9	E-1, F-1, G-2, G-6B, subthrust
August 1969	B-15	F-1, F-2, F-4, G-1, G-1B, G-3
August 1978	A-49	E-1
May 1979	B-35	G-1, G-3 + sidewall cores
October 1980	B-45	E-1, E-1A, F-1, F-4, G-1

RECOVERY OF BYPASSED OIL IN THE DUNDEE FORMATION USING HORIZONTAL DRAINS

Contract No. DE-FC22-94BC14983

Michigan Technological University
Houghton, Mich.

Contract Date: Apr. 28, 1994
Anticipated Completion: Apr. 27, 1997
Government Award: $800,000
(Current year)

Principal Investigator:
James R. Wood

Project Manager:
Chandra Nautiyal
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The principal objective of this project is to demonstrate the feasibility and economic success of producing oil from abandoned or nearly abandoned fields in the Dundee formation of central Michigan with the use of horizontal drilling technology.

Summary of Technical Progress

Project Management

Various subgroups met and worked on subtasks throughout the quarter. Weekly staff meetings were established at Michigan Technological University (MTU). Work began on three-dimensional (3-D) surface and volume visualizations in the statistical and visualization software package MatLab.

In February, cores of dolomitized Dundee reservoir from the demonstration well in Crystal field and from five other fields in the seven-county study area were described and sampled. Thin sections and fluid inclusion slides are being prepared, and petrographic, geochemical, and fluid inclusion analyses will be performed on these samples.

Reservoir Characterization

During fall 1995 the demonstration well for this project, the TOW No. 1-3 in Crystal field, was completed in the Dundee. For the first three months of operation, it produced 50 barrels of oil per day (BOPD) with no water cut. Because surface facilities were inadequate to handle full production, the well was produced for 12 h/d and shut in for 12 h/d. In

January 1996, new surface facilities were completed and production was raised to 100 BOPD. Production has varied from about 75 to 100 BOPD since that time. To date, the well has produced more than 10,000 bbl. The water cut remains at zero, and pressure has been maintained at 1445 psi by an active water drive. If expectations are met, the well will pay out in less than 1 yr and continue producing for at least 5 yr. Cronus Development Co. is tentatively planning to drill three more horizontal wells in the Dundee in Crystal field. Thus the tested play concept (that bypassed attic oil remained in the Dundee reservoir between wells that had been produced at excessively high flow rates and had coned water during primary production) appears to be correct. The TOW No. 1-3 HD-1 well is now a scientific success, and it appears that soon it will be an economic success.

Core and Log Analysis

The TOW No. 1-3 HD-1 well in Crystal field (the DOE project well) was spudded on Sept. 20, 1995, and cored and logged through the Dundee. One and one-half weeks later, 59.3 ft of core was recovered from the top of the Dundee, and the well was then drilled 150 ft below the base of the core to total depth (TD) at the top of the Detroit River anhydrite. The vertical well was then logged from TD at the base of the Dundee (3334 ft) to the base of casing (683 ft), which corresponds approximately to the base of the glacial till. Haliburton ran three consecutive log suites: a gamma-ray and dual laterolog with microresistivity, a lithodensity log (compensated formation density plus photoelectric factor), and a compensated neutron log. The logs were then correlated with a high degree of confidence and combined. The top portion of the Dundee displayed good oil staining in the core. The log suite, therefore, has good coverage of both the oil leg and water leg in the Dundee formation. This was later confirmed by residual fluid saturation analyses of core samples.

Data Measurement and Analysis

The uppermost Dundee reservoir was cored in the TOW No. 1-3 HD-1 well. The coring point was in the lowermost Bell Shale, immediately above the Dundee. A total of 59.3 ft of core was recovered out of a possible 60 ft. OMINI Laboratories in Houston ran a gamma-ray log on the core and photographed the core under plane and ultraviolet light to reveal sedimentary structures and heterogeneities in oil saturation. Porosity, permeability, and residual fluid saturation analyses were performed on whole-core samples taken at 1-ft intervals.

Dolomite extends almost to the top of the Dundee; the nonporous cap limestone, which is normally 10 to 15 ft thick in much of Crystal field, is only 2 ft thick in the TOW No. 1-3 well. The upper 15 ft of the Dundee is heavily fractured in core and contains centimeter-size vugs. Most fractures are subvertical with highly variable azimuths, but some fractures are developed at lower angles. Most fractures and vugs are lined with white, sparry dolomite. The top of the Dundee in the demonstration well was encountered 8 ft lower than projected. Together, these observations suggest that a topdown solution process (karst?) led to fracturing and collapse of the uppermost Dundee, which resulted in development of enhanced porosity.

The 29 ft of higher residual oil saturations at the top of the Dundee (3190 to 3219 ft) in the core indicate significant unrecovered oil. Beneath that, 7 ft of lower residual oil saturations (3219 to 3226 ft) indicate either a transition zone or a swept zone where the oil–water contact moved up as a result of primary oil production. In the water leg below 3226 ft, residual oil saturations are zero.

In February, the TOW No. 1-3 core was examined and several cyclic grainstone-to-mudstone units, which range in thickness from 5 to 15 ft, were identified. The grainstones appear to be leached and have high porosities and permeabilities. They may account for a large proportion of the reservoir volume. More importantly, most open fractures are subvertical and are confined to the top of the reservoir, whereas grainstone beds may form sheetlike fluid-flow conduits that extend down to the oil–water contact. These high-permeability grainstones, rather than fractures, may be responsible for the early watering out of many wells. Core samples were collected for thin-section and fluid-inclusion analysis. A detailed core study is planned this summer.

Calibration of Fourier transform infrared spectroscopy standards is now complete. Additional samples were analyzed but, because of contamination and instrumentation problems, will have to be rerun.

Database Management

The Multimedia Database Management System has been transferred to the commercial software package, Toolbook.

The Angstrom database of 51,359 wells and the initial production (IP) data for Winterfield field have been loaded into GeoGraphix along with three-dimensional (3-D) surface visualizations of structure and production data constructed for the Dundee reservoir. Crystal field data were loaded into GeoGraphix this quarter, and IP contour and bubble maps were prepared and the Angstrom database was edited. A new database composed of the deepest well in each section in Michigan was created. This reduced the number of working wells from more than 50,000 to about 10,000, while still providing sufficient information to produce the necessary stratigraphic and structural framework for the modeling effort.

Pseudoseismic Visualization

MatLab, a commercially available statistics and visualization package, was used to create 3-D visualizations of the Michigan Basin. The Angstrom database was loaded into MatLab and a 3-D volume visualization of the basin that shows the thickness and distribution of the Dundee and other key formations was produced (Fig. 1). Cross sections can be made through the basin at any angle.

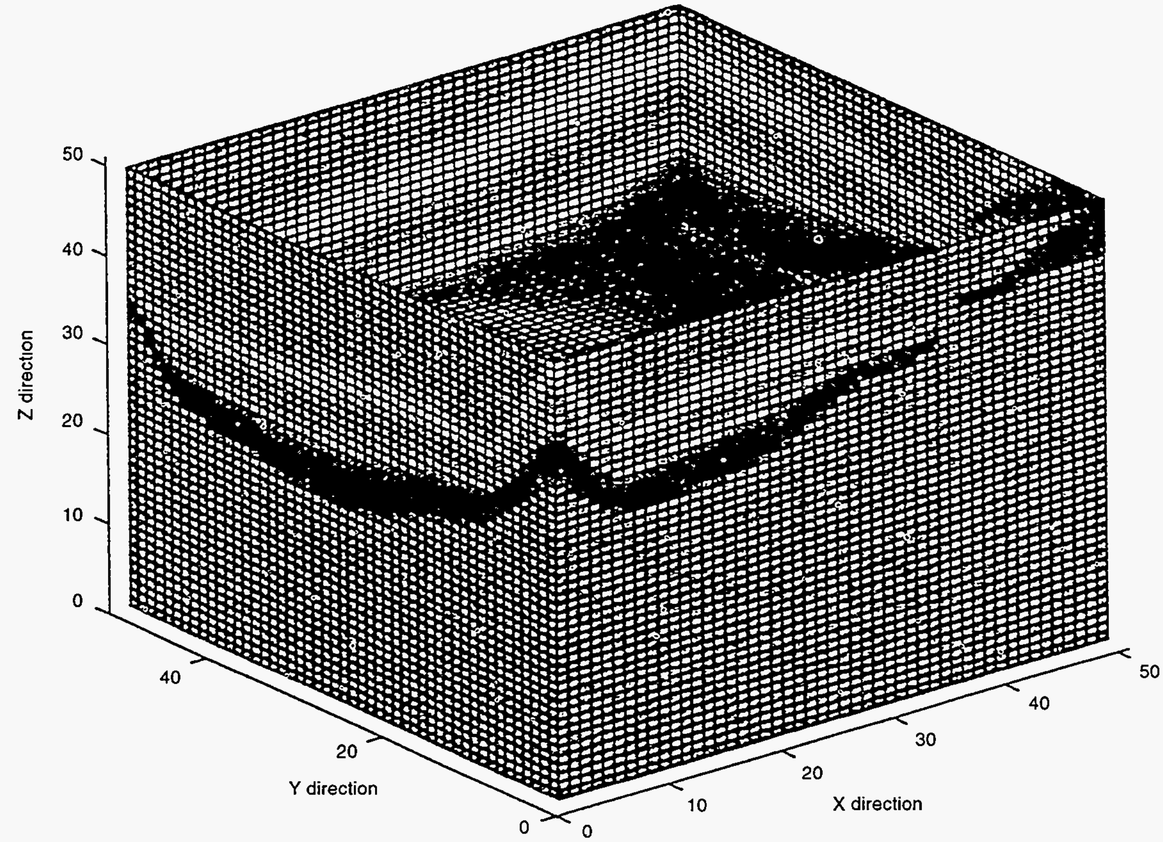


Fig. 1 Three-dimensional volume visualization of the Michigan Basin prepared in MatLab. The lower surface is the top Silurian. The Dundee Formation, Bell Shale, and Antrim Shale are shown above the Silurian surface. North is to the right along the X-axis.

MatLab is also being used to produce "pseudoseismic" sections from spontaneous potential (SP) and gamma-ray logs. These logs (log traces whose amplitudes have been color-coded to resemble seismic amplitude traces) can be selected from a map-view window and then displayed as well-log or pseudoseismic cross sections. This capability adds another useful dimension to the project's visualization capabilities. Current efforts are concentrating on the use of geostatistical methods to perform interwell correlations.

Technology Transfer

Internet Homepage

The Dundee Project has its own home page on the Internet. It can be reached at

http:/www.wmich.edu/geology/corelab/coreres.htm

Michigan Oil Field Research Consortium (MOFRC)

As the result of the *MOFRC Newsletter* and press releases, many people interested in horizontal drilling and the development of shallow-shelf carbonate reservoirs, both within the Michigan Basin and in other areas, have contacted project personnel. Project members have learned that companies are beginning to tie up Dundee acreage, presumably as a result of the success of this project well. Several calls were from principal officers of independent oil companies who requested information to help them initiate horizontal drilling programs.

Professional Papers and Presentations

In March 1996, two presentations featuring project accomplishments were made at the Michigan Department of Natural Resources annual symposium on "Michigan, Its Geology, Environment, and Resources." The project provided both a keynote speaker and a poster session. Also in March, a project overview was presented at the Petroleum Technology Transfer Council (PTTC) regional meeting in Grayville, Ill. In April project results were discussed informally with members of the Michigan oil and gas community at the Michigan Oil and Gas Association meeting in Mt. Pleasant, Mich.

Workshops

In January 1996, project members from MTU and Western Michigan University held a 2-d workshop at MTU to examine the core from the demonstration well, to discuss project results, and to plan next year's technical program and publication schedule.

INCREASING WATERFLOOD RESERVES IN THE WILMINGTON OIL FIELD THROUGH IMPROVED RESERVOIR CHARACTERIZATION AND RESERVOIR MANAGEMENT

Contract No. DE-FC22-95BC14934

City of Long Beach
Long Beach, Calif.

Contract Date: Mar. 21, 1995
Anticipated Completion: Mar. 20, 2000
Government Award: $147,166
(Current year)

Principal Investigators:
D. Sullivan
D. Clarke
S. Walker
C. Phillips
J. Nguyen
D. Moos
K. Tagbor

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The main objective of this project is the transfer of technologies, methodologies, and findings developed and applied in this project to other operators of slope and basin clastic reservoirs. Methods to identify sands with high remaining oil saturation and to recomplete existing wells with the use of advanced completion technology will be studied.

Wells that have the best oil production potential will be recompleted. The recompletions will be optimized by evaluating short-radius and ultrashort-radius lateral recompletions as well as other techniques.

A deterministic three-dimensional (3-D) geologic model will be developed and state-of-the-art reservoir management computer software will be used for the identification of the sands with high remaining oil saturation. The wells identified as having the best potential will be logged with a pulsed acoustic cased-hole logging tool. The application of the logging tools will be optimized in the laboratory by developing a rock-log model, which will allow the conversion of shear-wave velocity measured through casing into effective porosity and hydrocarbon saturation.

Summary of Technical Progress

Reservoir Characterization

Continued progress was made on developing rock-log and fluid-log models needed to calibrate, interpret, and understand acoustic log data. The laboratory strain measurement system was rebuilt to increase resolution. Researchers found that static compressive bulk moduli in cleaned Wilmington Ranger Zone samples are a factor of 4 less than the dynamic bulk moduli. Tests have also revealed a significant amount of viscous creep. This behavior is likely the result of the nonquartz constituents of the samples, including micas and clays. The presence of these materials will lead to both amplitude-dependent and frequency-dependent variations in elastic properties. This reveals the importance of correcting the lab data for strain rate and amplitude.

The sand previously identified as the Hx_1 sand has been renamed the Hx_0 sand. Researchers have reviewed newer penetrating electric logs and identified bypassed oil in fault block V. Suitable producer and injector recompletion candidates have been identified. Also, researchers have found remaining oil saturation in the Fo sand of the tar zone in fault block V. Suitable producer and injector recompletion candidates have been identified.

Deterministic 3-D Geologic Modeling

Tidelands Oil Production Company has made two subsidence corrections to the project database and continues to quality control the subzone markers and fault picks for each well in the project databases. New maps will be generated to help identify production units and potential logging candidates. Production units are sands that are isolated and can be exploited from existing wells along with selective reperforation of idle penetrating wells.

With the use of Earth Vision software, structural contour maps of the upper Terminal zone in fault block V at the Hx_1, Hx_0, Hx_2, and Hx sand markers were generated. The electric logs of all penetrating wells were examined, and these sand markers were identified and entered into Earth Vision. Researchers are now working on isopach maps for these same horizons as part of the deterministic geologic model. From these maps, researchers are reviewing potential recompletion candidates.

Pulsed Acoustic Logging

Two recompletion candidate wells in fault block V were identified by researchers for logging. Well J-15 has a deviation of 0°, and well J-120 has a deviation of 24°. Logging these wells tested a hypothesis (based on results from previous logging) that well deviation is one of the important determinants of shear-wave data quality. Data from logging J-15 (0°) were not very good because the quality of the shear and compressional waves was low. Data from well 167-W were extremely good, however, and will allow the calculation of a water line for Wilmington field. Well 167-W was logged again because J-120 was not prepared for logging.

Technology Transfer

Technology transfer activities include planning a field trip to Wilmington field for the American Association of Petroleum Geologists (AAPG) in association with their 1996 national meeting in San Diego. An article will also be placed in the AAPG guidebook for the national meeting.

Researchers are also planning the Stanford Rock and Borehole Geophysics Project Annual Meeting. Papers written and presented will include "Viscoelastic Response of Unconsolidated Reservoir Rocks," "Static and Dynamic Moduli of Unconsolidated Reservoir Rock," and "Status Report—DOE Funded Project to Detect Hydrocarbons Through Casing Using Acoustic Logs."

Researchers discussed log quality control issues at the Special Interest Group on Shear-Wave Logging of the Log Characterization Consortium.

Researchers at Tidelands Oil and the University of Southern California are developing a CD-ROM multimedia presentation on the history of this project. This historical record will be updated continuously and will be made available to other operators and the public in general. Periodically, CDs will be produced and distributed to other organizations as part of the technology transfer commitment of the project.

INCREASED OIL PRODUCTION AND RESERVES UTILIZING SECONDARY/ TERTIARY RECOVERY TECHNIQUES ON SMALL RESERVOIRS IN THE PARADOX BASIN, UTAH

Contract No. DE-FC22-95BC14988

Utah Geological Survey
Salt Lake City, Utah

Contract Date: Feb. 9, 1995
Anticipated Completion: Feb. 8, 2000
Government Award: $448,800
(Current year)

Principal Investigator:
M. Lee Allison

Program Manager:
Rhonda Lindsey
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The primary objective of this project is to enhance domestic petroleum production by demonstration and technology transfer of an advanced oil-recovery technology in the Paradox Basin, southeastern Utah. If this project can demonstrate technical and economic feasibility, the technique can be applied to approximately 100 additional small fields in the Paradox Basin alone and result in increased recovery of 150 to 200 million bbl of oil. This project is designed to characterize five shallow-shelf carbonate reservoirs (Fig. 1) in the Pennsylvanian (Desmoinesian) Paradox formation and to choose the best candidate for a pilot demonstration project for either a waterflood or carbon dioxide (CO_2)-flood project. The field demonstration, monitoring of field performance, and associated validation activities will take place in the Paradox Basin within the Navajo Nation. The results of this project will be transferred to industry and other researchers through a petroleum extension service, creation of digital databases for distribution, technical workshops and seminars, field trips, technical presentations at national and regional professional meetings, and publication in newsletters and various technical or trade journals.

Summary of Technical Progress

Three activities continued this quarter as part of the geological and reservoir characterization of productive carbonate buildups in the Paradox Basin: (1) reservoir facies

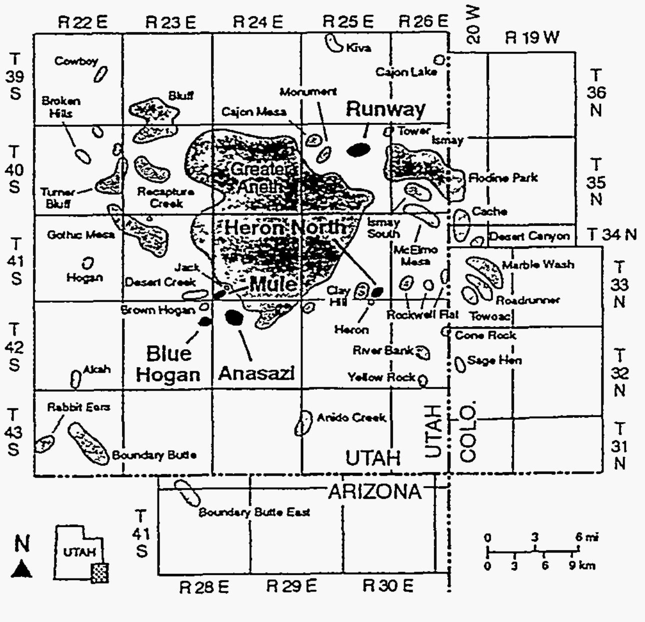


Fig. 1 Five shallow-shelf carbonate fields (indicated by dark shading with names in bold type) in the Paradox Basin, Navajo Nation, San Juan County, Utah.

characterization, (2) reservoir engineering analysis, and (3) technology transfer.

Reservoir Facies Characterization

Three generalized regional facies belts, each with unique types of facies, are identified in the Desert Creek zone of the Paradox formation (Fig. 2): (1) open marine, (2) shallow-shelf and shelf-margin, and (3) intra-shelf, salinity-restricted. All five project fields, as well as the other Desert Creek fields in the region, are located within the shallow-shelf and shelf-margin facies belt. This facies belt includes shallow-shelf carbonate buildups, platform-margin calcarenites, and platform-interior carbonate muds and sands.

Carbonate Buildups

The productive carbonate buildups are located in the shallow-shelf and shelf-margin areas. This facies can be divided into three types: (1) phylloid algal, (2) coralline algal, and (3) bryozoan.

Phylloid algal buildup facies. Phylloid algal buildup facies can be subdivided into shelter, mud-rich, and solution breccia facies. The shelter phylloid algal buildup facies represents a moderate energy environment with well-circulated water. Water depths ranged from 1 to 40 ft. The depositional fabric is bafflestone. Rocks representing this facies contain in situ phylloidal algal plates *(Ivanovia* and *Eugonophyllum),* encrusting forams (for example, *Tetrataxis),* soft peloidal mud, and minor amounts of internal sediment (mud or grains deposited after storms [suspended load]). These rocks have a high faunal diversity.

The mud-rich phylloidal algal buildup facies represents a moderate- to low-energy environment where the buildup was in a protected position with poorly circulated water. Water depths ranged from 3 to 40 ft. The depositional fabrics include bafflestone, wackestone, and mudstone. Rocks of this facies contain in situ phylloidal algal plates surrounded by lime mud, fine skeletal debris, and microfossils.

The solution breccia phylloidal algal buildup facies represents a moderate- to low-energy environment modified by

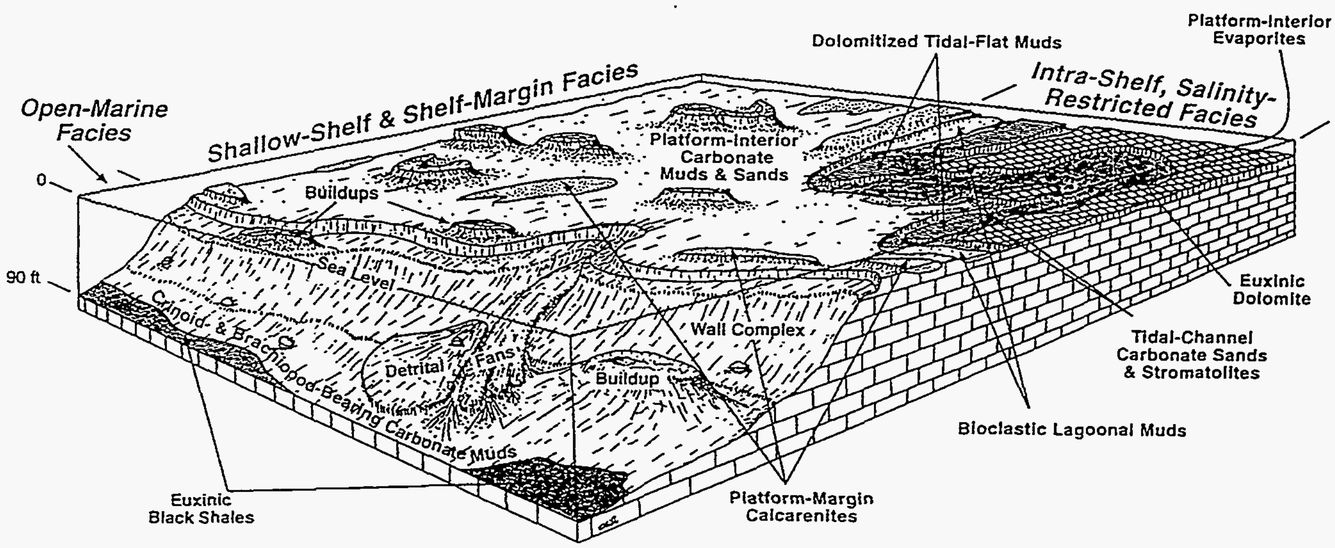


Fig. 2 Block diagram displaying major facies within regional facies belts for the Desert Creek zone, Pennsylvanian Paradox formation, southeastern San Juan County, Utah.

meteoric solution and collapse (karst to microkarst settings). Water level ranged from 3 ft above sea level to 30 ft below sea level. The depositional fabrics of this facies include disturbed mudstone and floatstone with some packstone. Rocks of this facies contain chaotic phylloid algal and exotic clasts, peloids, and internal sediments (muds).

The best stratigraphic hydrocarbon traps in the region are associated with phylloid algal facies. These traps are widely distributed, are small to moderate in size, and can be readily identified on seismic records. Shelter phylloid algal buildup facies is observed in Anasazi, Mule, and Runway fields (Fig. 1). Mud-rich phylloid algal buildup facies are also present in Anasazi, Runway, and Jack fields. The solution breccia phylloid algal buildup facies is observed in Mule, Runway, and Monument fields. Variable amounts of early marine cement are found in mud-rich (Monument field) and shelter (Blue Hogan and Brown Hogan fields) phylloid algal facies. Bafflestone areas within these facies traps have excellent reservoir properties where primary shelter porosity is well-developed. Anhydrite and early marine botryoidal to fibrous cements, however, occasionally plug pores.

Coralline algal buildup facies. Coralline algal buildup facies are located along the shallow-shelf margins facing open-marine waters or within the intra-shelf, salinity-restricted facies belt (where they are nonproductive). On the shallow shelf, this facies represents a low- to high-energy environment with well-circulated water. Water depths ranged from 25 to 45 ft. These buildups are a component of the wall complex (Fig. 2) in association with early marine cementation and are stacked vertically. They may surround other types of buildup complexes.

The depositional fabrics of coralline algal buildup facies are bindstone, boundstone, and framestone selectively dolomitized. Rocks representing this facies contain calcareous, encrusting, and bulbous coralline (red) algae, variable amounts of lime mud, microfossils, and calcispheres.

Coralline algal buildup facies are poor stratigraphic hydrocarbon traps and contribute minor amounts of oil to the production at Cajon Mesa and Runway fields (Fig. 1). These traps are rare, small, difficult to identify on seismic records, and require good well control for delineation. Although these reservoirs may appear good on geophysical logs, porosity and permeability are generally low.

Bryozoan buildup facies. Bryozoan buildup facies are located on the deeper flanks of phylloid algal buildup complexes. This facies represents a low-energy environment with well-circulated water. Water depths ranged from 25 to 45 ft. These facies were prevalent on the northeast part of the shallow shelf where winds out of the east and paleotopography from Mississippian-aged normal faulting produced better marine conditions for bryozoan colony development.

The depositional fabrics are bindstone, bafflestone, and packestone which are rarely dolomitized. Rocks of this facies contain the following diagnostic constituents: bryozoan colonies *(Chaetetes)*, small rugose corals, occasional small calcareous sponges and phylloidal algal plates, microfossils, and lime muds.

The bryozoan buildup facies are fair to poor stratigraphic hydrocarbon traps. This facies is productive at Cajon Mesa and Runway fields (Fig. 1). These traps are small, and their geometry is difficult to determine. Porosity is good, but pores (intraskeletal) are isolated unless connected by bryozoan sheets; permeability is variable. Minor to abundant amounts of early marine botryoidal to fibrous cement plugs pores.

Platform-Margin Calcarenites

The platform-margin calcarenite facies are located along the margins of the larger shallow shelf or the rims of phylloid algal buildup complexes. This facies represents a high-energy environment where shoals and/or islands developed as a result of regularly agitated, shallow marine processes on the shelf. Characteristic features of this facies include medium-scale cross-bedding and bar-type carbonate sand-body morphologies. Stabilized calcarenites occasionally developed subaerial features, such as beach rock, hard grounds, and soil zones. Water level ranged from 5 ft above sea level to 20 ft below sea level.

The depositional fabrics of the calcarenite facies include grainstone and packstone. Rocks representing this facies typically contain the following diagnostic constituents: coated grains, hard peloids, bioclastic grains, shell lags, and intraclasts.

Calcarenite facies are moderately good stratigraphic and diagenetic hydrocarbon traps, like those observed in Heron North, Heron, and Anasazi fields, for example (Fig. 1). These traps, however, have limited distribution and are relatively small and difficult to identify on seismic records. Grainstones within calcarenite facies traps have excellent reservoir properties where primary interparticle and secondary intercrystalline porosity (from dolomitization) are well-developed. Some calcarenites, however, have exclusive moldic pores that result in classic "heartbreak" reservoirs. In addition, bitumen (or solid hydrocarbons) sometimes plug intercrystalline and interparticle pores.

Platform-Interior Carbonate Muds and Sands

The platform-interior carbonate muds and sands facies are widespread across the shallow shelf. This facies represents a low- to moderate-energy environment. Muds and sands were deposited in subtidal (burrowed), interbuildup, and stabilized grain-flat (pellet shoals) settings intermixed with tubular and bedded tempestites. Water depths ranged from 5 to 45 ft.

The depositional fabrics of the platform-interior carbonate muds and sands facies include grainstone, packstone, wackestone, and mudstone. Rocks representing this facies typically contain the following diagnostic constituents: soft pellet muds, hard peloids, grain aggregates, crinoids and associated skeletal debris, and fusulinids.

The platform-interior carbonate muds and sands facies can contain reservoir-quality rocks if dolomitized. This facies is present in Anasazi, Heron, Heron North, and Runway fields (Fig. 1).

Reservoir Engineering Analysis

During the quarter, team members performed the following reservoir engineering analysis tasks: (1) finalization of the experimental program with the completion of capillary pressure and relative-permeability measurements on the mound-core interval (lower part of the carbonate buildup) from the Anasazi No. 1 well, Anasazi field; (2) finalization of well test analysis with the completion of a successful analysis and interpretation of the well tests conducted on the Big Sky No. 6E well near Clay Hill field (Fig. 1); and (3) initialization and completion of equation-of-state (EOS) tuning using original black oil pressure–volume–temperature (PVT) data from the Anasazi No. 1 well and the CO_2 swelling test data obtained on fluids from the Anasazi No. 5L-3 and Anasazi No. 6H-1 wells, Anasazi field.

Relative-permeability work consisted of determining oil–brine and gas–oil capillary pressure data employing ultracentrifuge technology. These tests were conducted at reservoir temperature (130 °F). Ultracentrifuge data were used to determine core-plug wettability and relative-permeability values. Restored-state core plugs were used for the experimental study. The data indicate a mixed wettability condition with a slightly stronger water-wetting tendency than previously found for the supra-mound interval (upper part of the carbonate buildup) samples from the Anasazi No. 6H-1 well. An oil–gas imbibition experiment provided data on the value of the trapped gas saturation. A value of 11.2% was determined from the experiment.

Well test analysis of various Paradox Basin wells was finalized with the completion of analysis work on the Big Sky No. 6E well. The test was successfully interpreted with the use of a homogeneous model, which is consistent with production data because only the supra-mound interval is present and should behave as a single-porosity system. To successfully analyze other wells (for example, the Anasazi No. 1), a dual-property model was required to represent the fluid communication between the supramound and mound-core intervals. Figures 3 and 4 illustrate the quality of the match and the reservoir parameters required to achieve this match.

One of the first steps in conducting a compositional simulation study of the Anasazi reservoir is the calibration or tuning of an EOS to provide a means of calculating or predicting the complex phase behavior associated with CO_2 displacements processes. All the experimental fluid property data available on the Anasazi reservoir were used to tune a Peng–Robinson EOS. This included the original black oil PVT fluid study and the recently completed CO_2 swelling tests data. Two fluid characterizations employing 11 and 13 pseudo components were successfully used in the calibration work. Both characterizations, in which EOS parameters

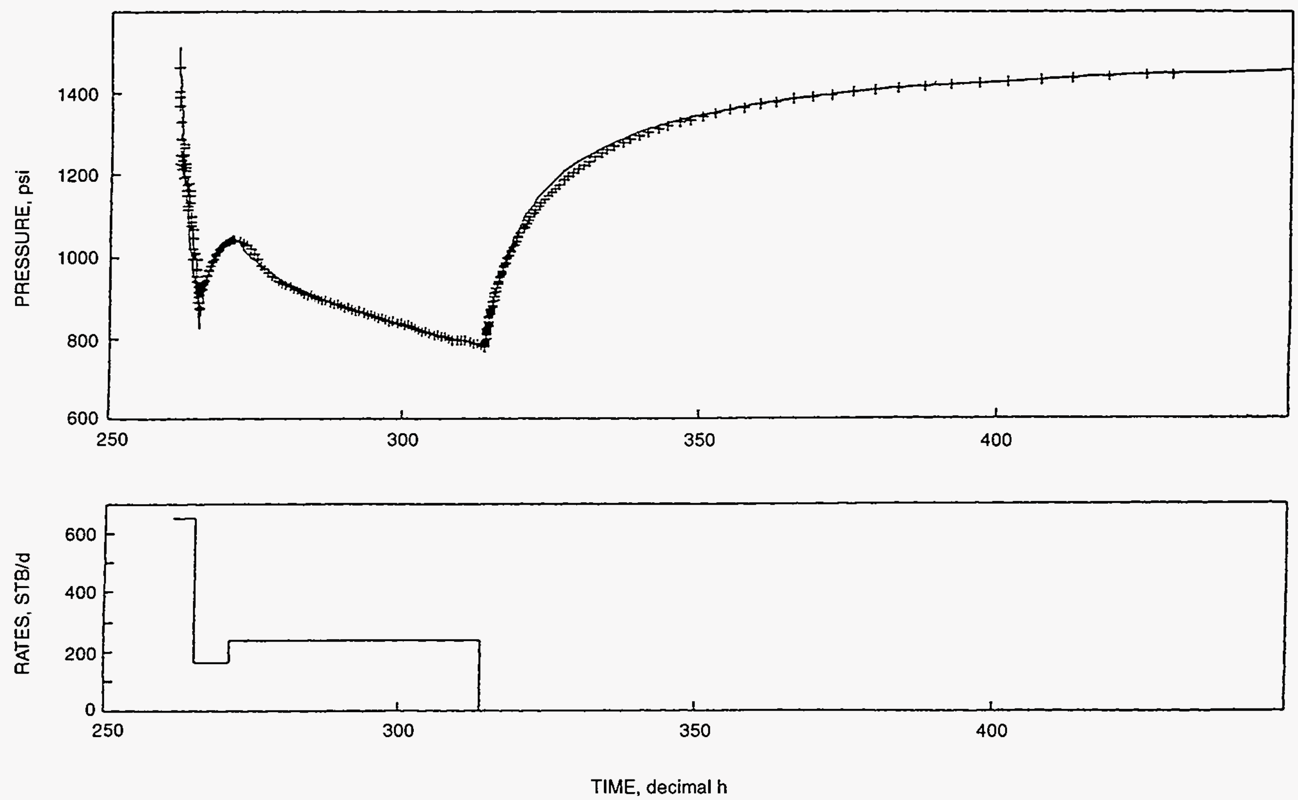


Fig. 3 Well flow buildup test analysis of the Big Sky No. 6E well near Clay Hill field (see Fig. 1 for field location) displaying pressure vs. time match. Homogeneous reservoir simulation data: well storage, 0.0900 bbl/psi; skin, –5.30; permeability, 6.50 mD; permeability–thickness, 65.0 mD/ft; initial pressure, 1515 psi. —, computed response. +, measured pressure data.

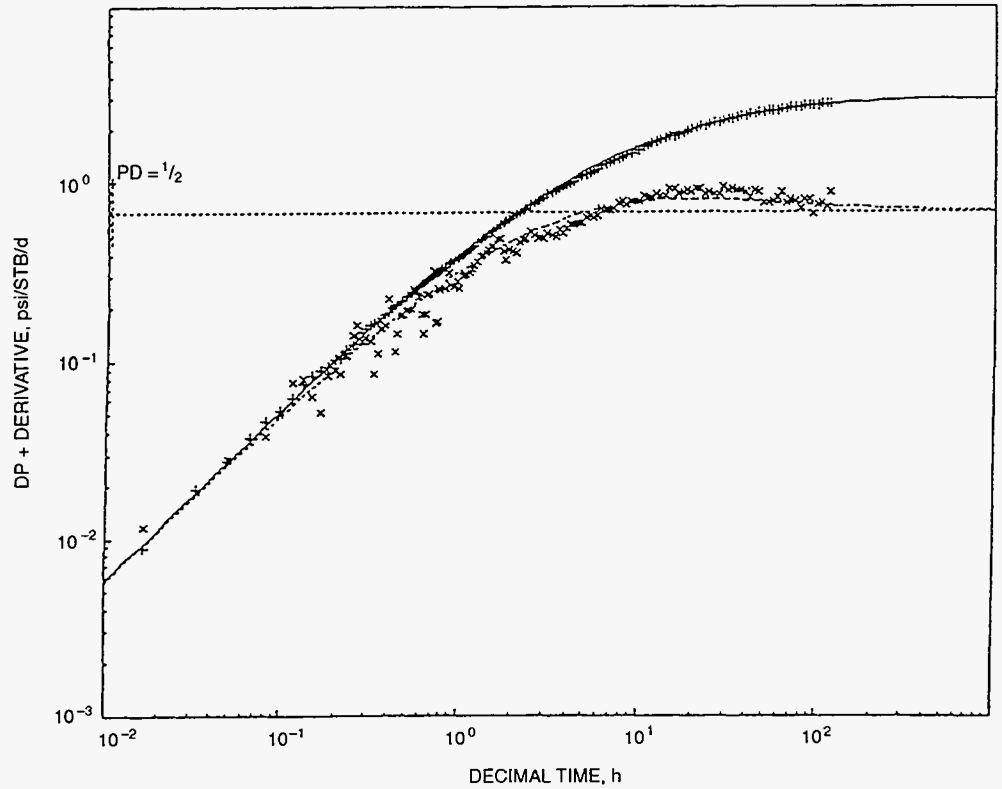


Fig. 4 Well flow buildup test analysis of the Big Sky No. 6E well displaying pressure difference and pressure derivative match. Homogeneous reservoir simulation data: well storage, 0.0900 bbl/psi; skin, –5.30; permeability, 6.50 mD; permeability–thickness, 65.0 mD/ft; initial pressure, 1515 psi; smoothing coefficient, 0.0. —, computed response. +, measured pressure data.

derived from the tuning work were used, have been used to reliably match all experimental data. Also, the calibrated EOS was used to conduct a series of multiple-contact experiments designed to approximately model a CO_2 displacement process. Results of this work provide insight into the conditions (compositions and pressures) required to develop miscibility.

Technology Transfer

Regulatory Issues

The Utah Geological Survey (UGS) director and energy section chief were invited to meet with county commissioners from every oil-producing county in the State, representatives from the State Tax Commission, and Utah Association of Counties to address regulatory issues affecting future oil production and activities. State tax incentives for enhanced oil-recovery (EOR), particularly CO_2 floods, and horizontal-drilling projects were discussed. UGS personnel used the U.S. Department of Energy-sponsored Bluebell and Monument Butte projects (both Class 1) and Paradox Basin project (Class II) as examples of the economic potential of EOR and horizontal drilling to explain technical aspects of such projects.

Personnel from the UGS also met with the Utah Department of Natural Resources executive director and representatives of the Utah Office of Energy and Resource Planning. That meeting helped establish the department's position on a state legislative bill that provides tax incentives for EOR and horizontal-drilling projects.

The UGS is preparing a white paper in cooperation with the Utah Office of Energy and Resource Planning outlining a state strategic initiative to increase oil production in Utah. The strategy will focus on the encouragement of government–industry partnerships similar to those established in the Paradox Basin and Bluebell projects and modification of tax philosophies and regulatory processes to take into account varying reservoir conditions.

UGS on the Internet

The UGS has established a home page on the Internet (http://utstdpwww.state.ut.us/~ugs/), which links to information on our geologic programs (Paradox Basin, Bluebell field, and Ferron Sandstone) and the latest issue of *Petroleum News*.

IMPROVED OIL RECOVERY IN FLUVIAL-DOMINATED DELTAIC RESERVOIRS OF KANSAS—NEAR TERM

Contract No. DE-FC22-93BC14957

University of Kansas
Center for Research, Inc.
Lawrence, Kans.

Contract Date: Apr. 4, 1995
Anticipated Completion: Dec. 31, 1998
Government Award: $2,007,446
(Current year)

Principal Investigators:
Don W. Green
G. Paul Willhite

Project Manager:
Rhonda Lindsey
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this project is to address waterflood problems of the type found in Cherokee Group reservoirs in southeastern Kansas and in Morrow sandstone reservoirs in southwestern Kansas. Two demonstration sites operated by different independent oil operators are involved in the project. The Nelson Lease (an existing waterflood), located in Allen County, Kans., in the northeastern Savonburg field, is operated by James E. Russell Petroleum, Inc. The Stewart field (on latter stage of primary production), located in Finney County, Kans., is operated by North American Resources Co.

Summary of Technical Progress

Savonburg Field Project

Water Plant Development

A new motor and wiper arm were installed on top of the air flotation unit (AFU). A data logger was placed in service to monitor operating time of the unit. Injection water quality was measured by Millipore filtration test to correlate with turbidity measurements from the new calorimetric testing equipment. In March the AFU was cleaned and the air turbines replaced from the inside without removing the motors. A 4-in. drain line was changed to polyvinyl chloride (PVC) piping, and a valve was installed for greater access. Longer wiper brushes were installed to remove the solids. The flotation aid chemical pump was moved from the AFU building to the transfer pump station. Quality continues to improve, and suspended solids are being reduced. Turbidity is being monitored by use of the new Hach Dr-700 measuring device.

The plant bag filter holders, which were clogged with scale, were cleaned. The slop tank was also cleaned at the end of February. High winds broke an electrical connection on the power pole for the water supply well.

The need for better measurement of flow rate of the various plant water streams was defined in previous reports. A series of tests were conducted with the use of externally applied Doppler flowmeters at various locations. These meters were unsatisfactory for this application. The sensors require a reflection from either particulates or air bubbles in the water, but the water is too clean for them to work consistently.

Pattern Changes and Wellbore Cleanup

In February, well KW-9 was taken off injection in preparation for a workover. Well K-42 was cleaned with a lubricator acid chemical treatment. Injection lines RW-6, KW-11, RW-12, and H-12 were flushed. Producing wells H-3, K-41, and K-54 were serviced twice, O-1 and H-25 were serviced once.

In March the new injection well (RW-20) was completed and hooked up. Fluid was swabbed from the casing and 110 gal of acid with chemical additives was spotted over the completion interval. Two intervals totaling, 15 ft were perforated. Additional treatment will be performed to initiate injection.

A workover was performed on well KW-9 to limit injection fluid leak-off. A packer was run on 2-in. tubing and set at 638 ft. A head was installed, and tubing and casing pressures are being monitored. Well HW-23 was washed and jetted with an acid–chemical mixture. Well RW-12 was treated with an acid–chemical mixture with the use of the coil tubing unit. Producing wells H-3 and H-25 were serviced twice, and H-9 and K-45 were serviced once.

Field Operations

Normal field operations have included monitoring wells on a daily basis; repairing waterplant, piping, and wells as required; collecting daily rate and pressure data; and solving any other daily field operational problem that might occur. Production statistics are summarized in Table 1.

Stewart Field Project

Design/Construct Waterflood Plant

Field office construction was completed. An emergency shutdown and call-out system was installed. The plant and tank battery monitoring computer was installed in the office.

Design/Construct Injection System

Water supply rates were increased to approximately 5400 barrels of water per day (BWPD), making a total injection rate of approximately 5600 BWPD (including

TABLE 1

Savonburg Field Oil Production

Month	Oil production, BOPD	Month	Oil production, BOPD
October 1993	26.4	February 1995	25.3
November 1993	30.7	March 1995	22.4
December 1993	32.0	April 1995	22.4
January 1994	30.8	May 1995	25.0
February 1994	30.9	June 1995	23.9
March 1994	30.3	July 1995	26.8
April 1994	29.1	August 1995	25.2
May 1994	28.5	September 1995	24.8
June 1994	30.3	October 1995	24.4
July 1994	28.9	November 1995	24.4
August 1994	24.6	December 1995	26.3
October 1994	23.0	January 1996	28.0
November 1994	25.7	February 1996	29.2
December 1994	27.8	March 1996	27.2
January 1995	27.0		

produced water). Both water supply wells are being run continuously to supply this rate. Both quintiplex injection pumps are being run continuously to inject at a rate of 5600 BWPD. Corrosion coupons were installed at each supply and injection well.

Waterflood Operations and Reservoir Management

The injection rate was increased to 5600 BWPD the first week in February. Testing of the producing wells continued with portable test trailers and monitoring fluid levels. A new gas-fired fluid level instrument was purchased to assist with well test coverage. Well tests indicated a production response in two producing wells during the last 10 days of March. The total 45 barrels of oil per day (BOPD) production increase comes from two producers that are directly offsetting injectors. Injection volumes and pressures at each injection well continued to be monitored. Daily production and injection rates are shown in Fig. 1.

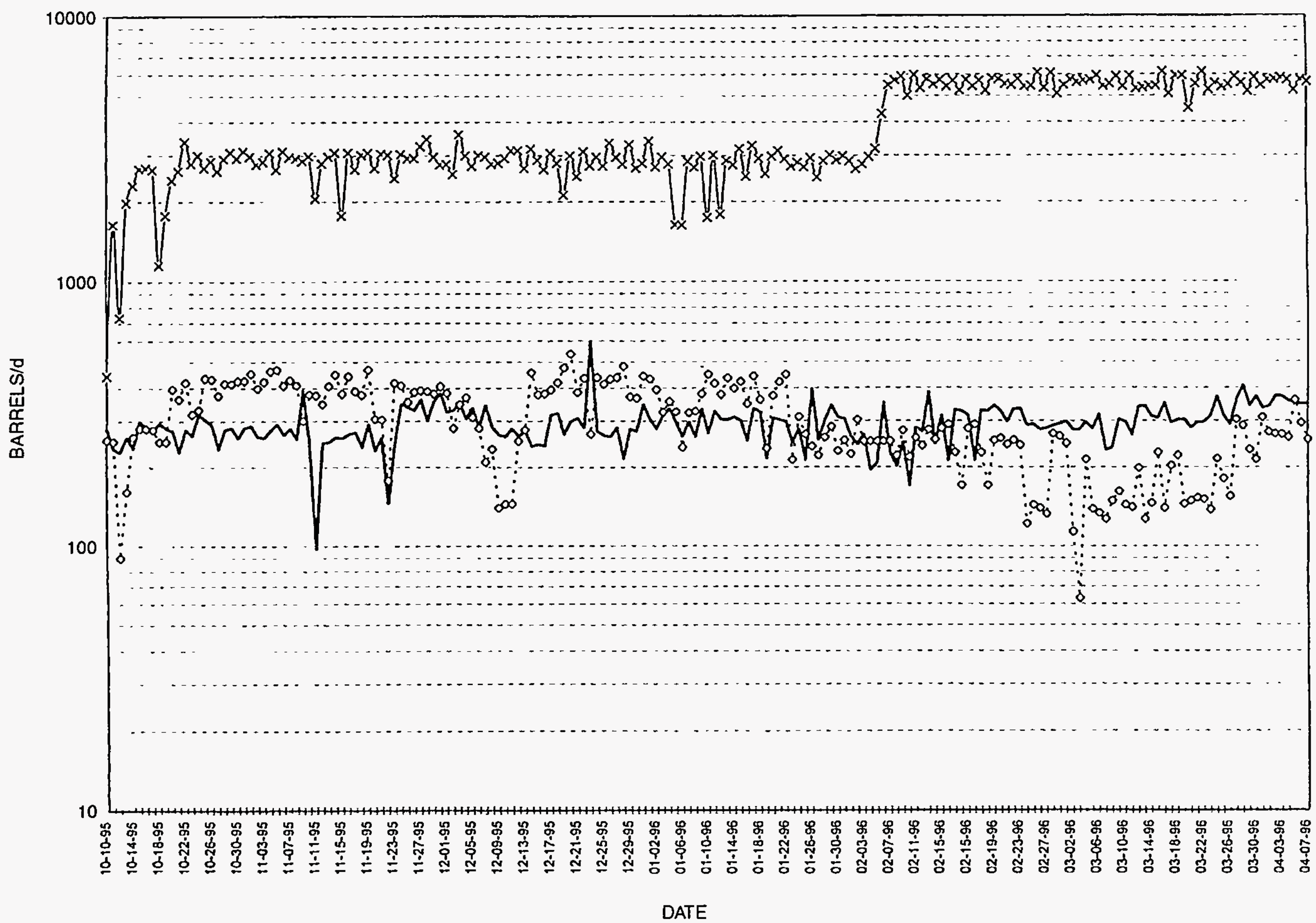


Fig. 1 Stewart field waterflood results. ×, total barrels of water injected. —, barrels of oil produced. ◇, barrels of water produced.

This project moved into the field office on March 1 and set up injection plant and tank battery computerized monitoring system equipment and emergency shutdown and callout equipment. Simulation software and hardware were purchased for the Denver office.

Technology Transfer

Information was prepared and presented on the Stewart field as part of the Traveling Workshop Series for selected Class 1 near-term projects

ADVANCED RESERVOIR CHARACTERIZATION AND EVALUATION OF CO_2 GRAVITY DRAINAGE IN THE NATURALLY FRACTURED SPRABERRY RESERVOIR

Contract No. DE-FC22-95BC14942

Parker and Parsley Petroleum USA, Inc.
Midland, Tex.

Contract Date: Sept. 1, 1995
Anticipated Completion: Sept. 1, 1997
Government Award: $1,427,977
(Current year)

Principal Investigator:
David Schechter

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this research and the pilot project planned is to test the feasibility of CO_2 for recovering oil from the naturally fractured Spraberry Trend area in the Midland Basin. This notoriously marginal reservoir has confounded operators for 40 yr with rapid depletion, low primary recovery, disappointing waterflood results, and low ultimate recovery, yet the tremendous areal coverage and large amount of remaining oil (up to 10 billion bbl) warrant further investigation to expend all possible process options before large numbers of Spraberry wellbores need to be plugged and abandoned.

CO_2 injection on a continuous, pattern-wide basis has not be attempted in the Spraberry Trend because of the obvious existence of a network of naturally occurring fractures. It has become clear in recent years, however, that, by neglecting CO_2 injection as an option in fractured reservoirs[1] potential viable projects may have been overlooked.

The 15-well pilot field demonstration and supporting research will provide the necessary information to quantify the conditions whereby CO_2 flooding would be economic in the Spraberry Trend.

Summary of Technical Progress

Field Demonstration

The E. T. O'Daniel well No. 37, the central production well in the projected 15-well CO_2 pilot, was spudded by Parker and Parsley Petroleum USA, Inc., on Sept. 27, 1995. This core well confirmed that the 1U and 5U zones are the primary reservoir zones in the Upper Spraberry. Therefore the 1U and 5U zones were the only zones that were perforated and stimulated. The well was completed after extensive open-hole logging and has been pumping since December 1995. Monthly oil, water, and gas production data are shown in Fig. 1. Production has been steady at about 11 barrels of oil per day.

The well has been shut in and a pressure build-up test is being conducted. A pulse test using current wells outside the proposed pattern area will be performed in the third quarter. The pulse test will confirm the in situ direction of the local fracture trend and verify either an east-west direction as indicated by Schlumberger's formation microimager (FMI) dipmeter and core data or the traditional northeast-southwest trend measured in past surveys. The pulse test could also help to determine whether the stress state of the reservoir has been altered. It is important that the pilot injection wells align along a line parallel to the dominant fracture trend. The pulse test should also provide indication of the permeability anisotropy in the pilot area.

Open-Hole Logging

Open-hole logs were run in the Upper Spraberry for net pay correlations, fracture identification, and core-log correlation.

Fracture Identification

Results of FMI and core-observed fracturing from the 5U pay zone were recorded. Samples were taken for paleomagnetic orientation. Generally, all data are in agreement in regard to fracture orientation (N. 85 °E.). The pulse test will demonstrate whether or not the east-west orientation is a near-wellbore phenomenon created by induced fractures as a result of the stress state changing over time or a northeast-southwest orientation that was observed and documented in the 1960s.

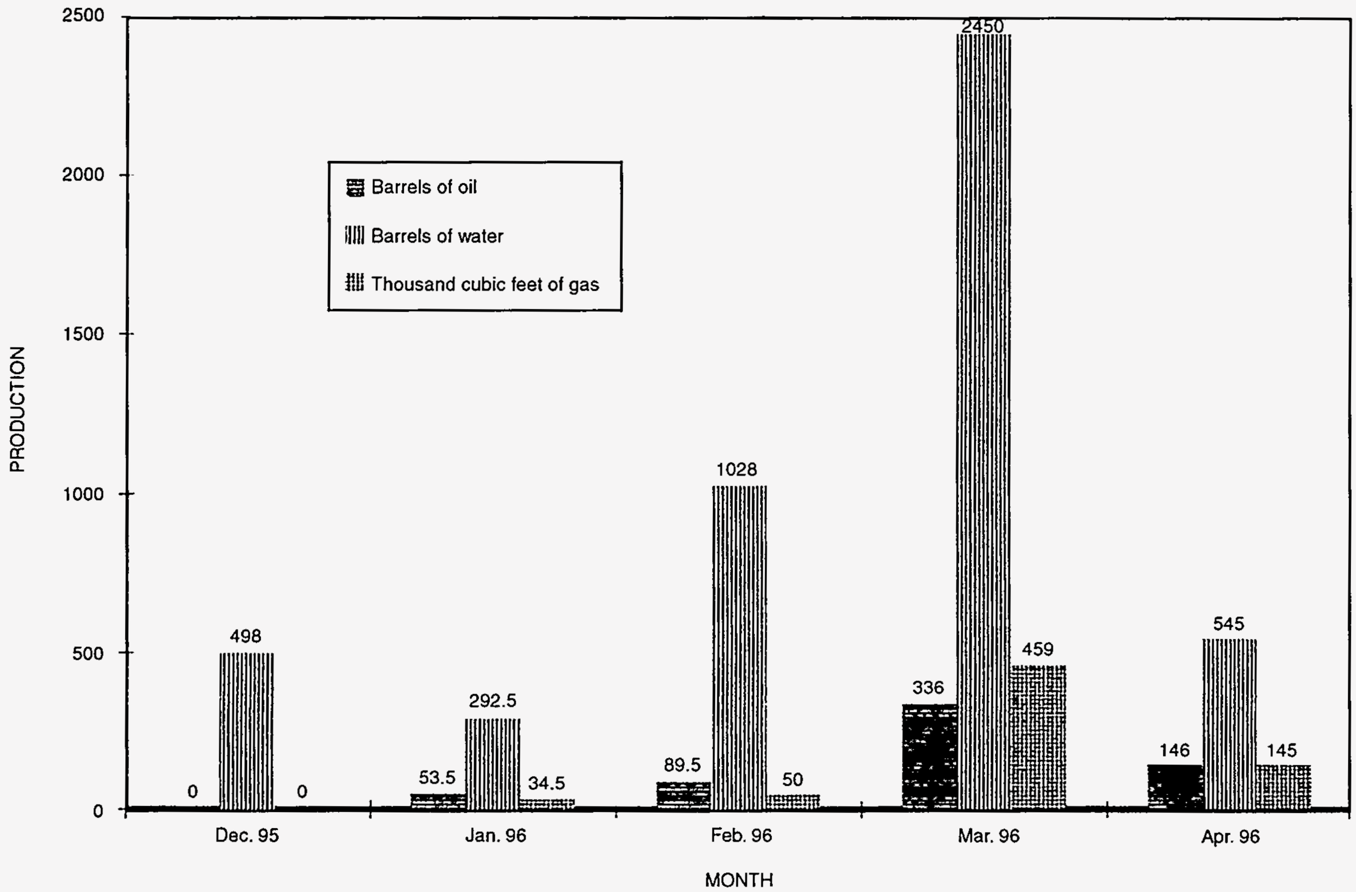


Fig. 1 Monthly production report of the DOE pilot well E. T. O'Daniel No. 37.

Net Pay Identification

Researchers here previously demonstrated[2] that classic shaly-sand analysis could accurately quantify thin, fractured pay zones that characterize the Spraberry Trend. The acquisition of core data proved that the 1U and 5U contain a majority of the hydrocarbon storage, although other thin intervals with a greater clay content than the 1U or 5U and less than 1 ft thick are also present.

Another revelation was the sharp contrast between pay and nonpay as observed by fluorescence. Identification and mapping of thin pay zones that comprise the Spraberry sands are important first steps when considering any improved oil recovery (IOR) technique in the future. Geografix Inc. has donated its log and seismic analysis software to the project. QLA2 was used to develop a shaly-sand model specifically for the Spraberry Trend area, and the results are presented in the following section.

Shaly-Sand Model

Upper Spraberry core from the DOE pilot well E. T. O'Daniel No. 37 was available for this investigation. The core was examined to determine gross lithologic properties and to correlate core properties with the wireline log response in addition to development of a rock model. Thin sections were made to determine the distribution of microscopically visible porosity and to investigate diagenesis, cementation, etc. Porosity, water saturation, and permeability were obtained from whole core analysis. Permeability distribution in the main pay was measured by minipermeameter and found to correlate well with whole core analysis. Minipermeameter measurement of the entire pay zone indicated that the matrix by itself is relatively homogeneous, usually in the range of 0.1 to 1.0 mD. Two main pay zones, 1U and 5U (each approximately 10 ft thick separated by 150 ft of nonpay), were clearly identified by oil fluorescence.

Effective water saturation and effective porosity were calculated from shaly-sand log interpretation with the use of both conventional m & n ($m=2$, $n=2$) and core-derived m & n ($m=1.66$, $n=1.46$). Conventional m & n values overestimate the water saturation, whereas water saturation calculated with core-derived m & n values shows good agreement with core-measured water saturation. Also, for the Spraberry Trend, the automatic compensation method (ACM) and the Fertl method of shaly-sand interpretation perform better than the dual water method. Effective water saturation calculated from the dual water method is much higher than that calculated from the ACM and the Fertl method.

The Larionov nonlinear relationship was used to calculate the volume of shale from the gamma-ray log (see Fig. 2 for a comparison of linear vs. nonlinear models). The result was compared with ultraviolet observations of fluorescing intervals which show a clear distinction between oil-bearing sand and muddy zones containing no oil. Shaliness factor q and effective porosity were calculated from log and were cross-plotted on a shaly-sand producibility chart (q-plot) (Fig. 3) to determine whether the volume of shale is high enough to drastically reduce producibility. On the basis of fluorescing intervals observed in the core along with q-plot analysis, researchers here contend that shale volume less than 15%, q less than 15, and effective porosity higher than 7% provide accurate cut-off criteria for identification of fluorescing intervals in Spraberry Trend area reservoirs. Thin-section analysis confirms the cutoff criteria by observation of visible porosity in oil-bearing intervals, whereas no visible porosity is observed in the nonpay muddy zones.

Matrix minerals were identified by thin-section petrography, scanning electron microscopy, and X-ray diffraction and compared with matrix minerals derived from open-hole logs. The pay zones are composed predominantly of quartz and feldspar with some dolomite. Clay minerals are mostly illite.

The success of shaly-sand analysis now provides quantitative methodology to map the thin pay sands that comprise the Spraberry Trend reservoirs. This technique can be applied to the entire Trend to understand pinch-off and thinning of the sands near the fringe of the basin. Researchers here are currently attempting to apply the analysis to old case-hole logs.

Technology Transfer

Two papers[1,2] were presented at the Permian Basin Society of Petroleum Engineers (SPE) meeting in Midland, Tex., in March 1996, and a poster was also prepared (SPE 35443).

A brief description of the Spraberry Class III field demonstration along with a photograph of a mineralized natural fracture can be found on the project home page: http://baervan.nmt.edu/projects/spraberry.html.

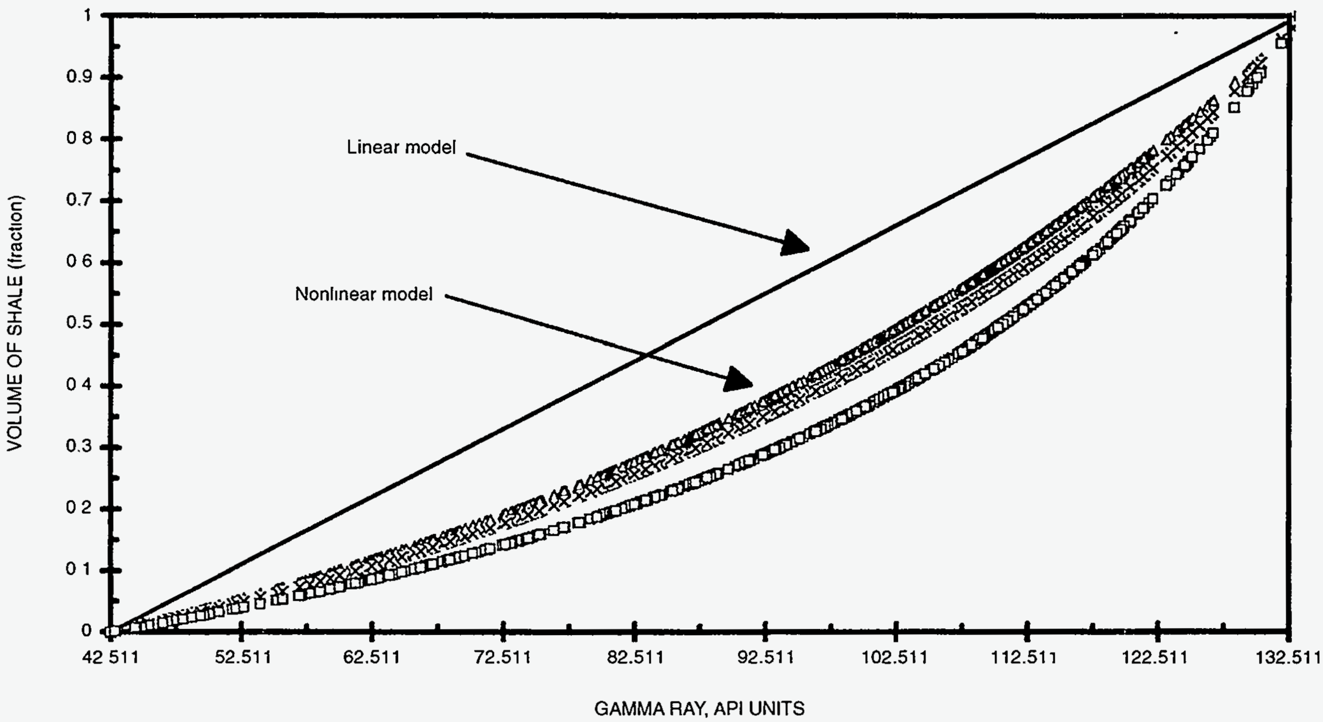


Fig. 2 Comparison of the linear vs. nonlinear models of shale volume calculated from gamma-ray log (upper Spraberry, E. T. O'Daniel No. 37). —, Linear. Δ, Larionov. ×, Clavier. □, Stieber. (From *Introduction to Wireline Log Analysis*, Western Atlas International, Inc., Houston, Texas, 1992.)

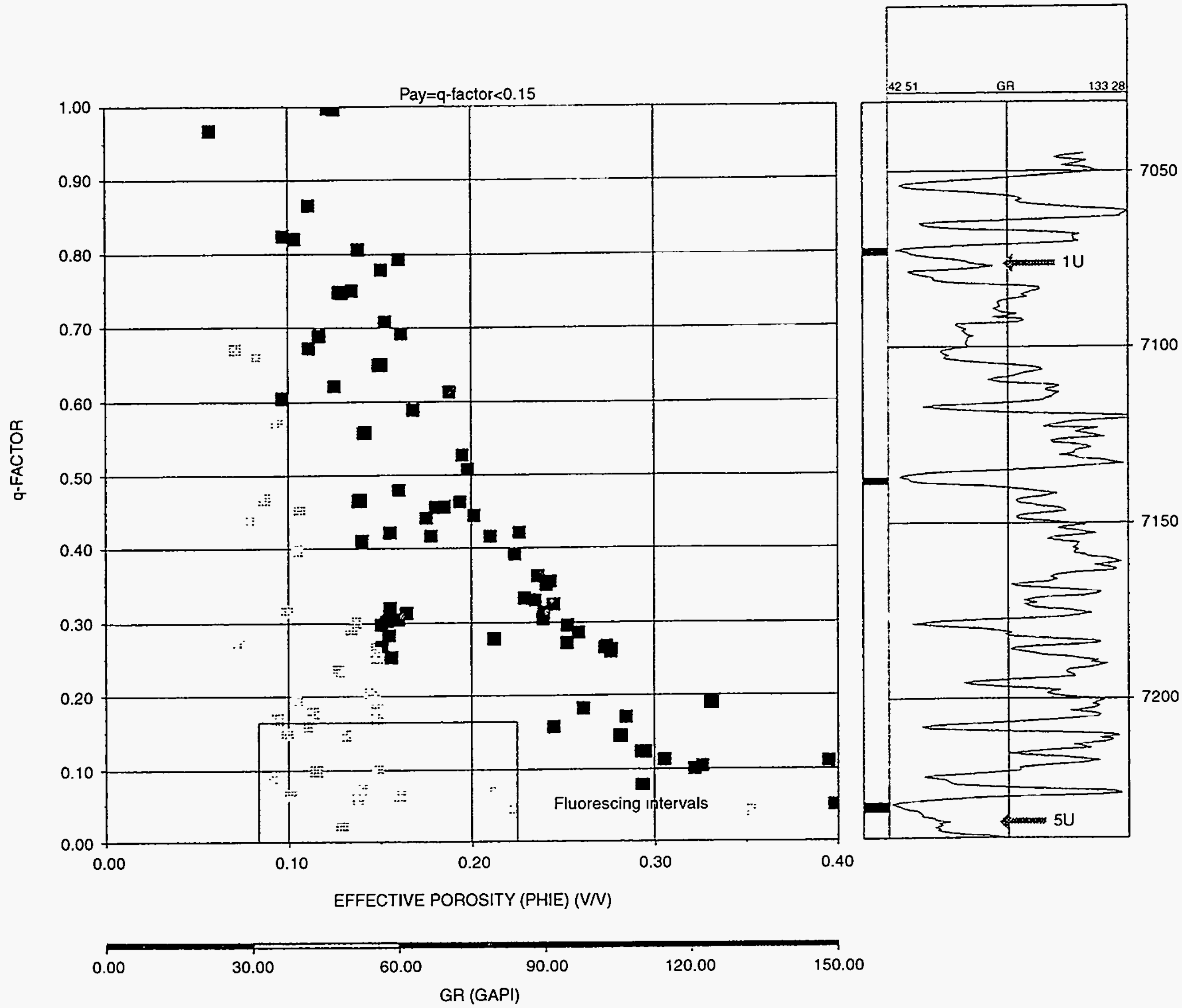


Fig. 3 Shaly-sand producibility chart (q-plot) for the DOE pilot well E. T. O'Daniel No. 37, Upper Spraberry. Intervals (1U and 5U) appearing in the box fluoresced strongly under ultraviolet light.

References

1. D. S. Schechter, P. McDonald, T. Sheffield, and R. Baker, *Reservoir Characterization and CO_2 Pilot Design in the Naturally Fractured Spraberry Trend Area,* paper SPE 35469 presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Tex., March 27–29, 1996.
2. A. K. Banik and D. S. Schechter, *Characterization of the Naturally Fractured Spraberry Trend Shaly Sands Based on Core and Log Data,* paper SPE 35224 presented at the Permian Basin Oil and Gas Recovery Conference, Midland, Tex., March 27–29, 1996.

ADVANCED RESERVOIR CHARACTERIZATION IN THE ANTELOPE SHALE TO ESTABLISH THE VIABILITY OF CO_2 ENHANCED OIL RECOVERY IN CALIFORNIA'S MONTEREY FORMATION SILICEOUS SHALES

Contract No. DE-FC22-95BC14938

Chevron USA Inc.
Bakersfield, Calif.

Contract Date: Feb. 7, 1996
Anticipated Completion: June 11, 1998
Government Award: $2,334,048
(Current year)

Principal Investigator:
Stephen C. Smith

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The primary objective of this research is to conduct advanced reservoir characterization and modeling studies in the Antelope Shale reservoir. Characterization studies will be used to determine the technical feasibility of implementing a CO_2 enhanced oil recovery (EOR) project in Buena Vista Hills field. The Buena Vista Hills pilot CO_2 project will demonstrate the economic viability and widespread applicability of CO_2 flooding in fractured siliceous shale reservoirs of the San Joaquin Valley. The research consists of four primary work processes: reservoir matrix and fluid characterization, fracture characterization, reservoir modeling and simulation, and CO_2 pilot flood and evaluation. Work done in these areas can be subdivided into two phases or budget periods. The first phase of the project will focus on the application of a variety of advanced reservoir characterization techniques to determine the production characteristics of the Antelope Shale reservoir. Reservoir models based on the characterization work will be used to evaluate how the reservoir will respond to secondary recovery and EOR processes. The second phase of the project will include the implementation and evaluation of an advanced EOR pilot in the West Dome of the Buena Vista Hills field.

Summary of Technical Progress

The project has just started, so this report will summarize the technical work done during pre-award activities. Pre-award technical efforts included cross-well seismic field trial, downhole video logging of producing wells, and acquisition and installation of state-of-the-art workstation and modeling software.

Cross-Well Seismic

A cross-well seismic project was conducted by Tomoseis, Inc., in wells 553-26B and 554-26B of the Buena Vista Hills field in September 1995. The objectives of the cross-well project were to

- Acquire and process high-resolution cross-well seismic data to better characterize the Antelope Shale reservoir prior to drilling a CO_2 injection well.
- Provide cross-well data for attenuation tomography processing.
- Provide high-resolution cross-well reflection sections for reservoir characterization.
- Evaluate piezoelectric source technology in the Antelope Shale.

The cross-well seismic project at Buena Vista Hills was unsuccessful. Excessive noise levels, as a result of gas entry into the wellbore, were observed in both wells. The wellbore must be fluid-filled to couple signals from the formation to the receivers. The noise levels were excessive in all conditions where the receivers were in fluid. Direct comparison of hydrophone and geophones in areas with noise levels as observed is not available. If fluid and gas flow can be stopped in the logging interval, such as in a cased hole, clamped receivers in an air-filled well should produce much lower noise levels.

Video Logging

Downhole video logs were run on wells 553-26B and 554-26B in October 1995 to determine exactly where oil, gas, and water enter the wellbore. Downhole video logs were used to determine fluid entry because the wells are produced on pump, and there was not sufficient room to run production logs in the annulus between tubing and the slotted liner. Furthermore, interpretation of production logs in low-volume producing wells can be extremely subjective, and video logging provided the opportunity to obtain more definitive data.

Oil and water entries were observed in the air-filled portion of well 554-26B under both shut-in and flowing conditions. Gas entry was observed in the air-filled part of the borehole during flowing conditions only and in the fluid-filled part of the borehole during both shut-in and flowing conditions. Oil entry was concentrated in a 25-ft-thick zone just below "P" point, although evidence for oil entry near the bottom of the well was also observed. The shut-in fluid level was found at mid-perf level and was static. Gas bubbles obscured vision in the fluid-filled part of the borehole.

This evidence suggests that significant crossflow occurs during shut-in. Gas apparently flows out of deeper parts of the reservoir and into lower pressure zones, and water flows from shallower (and possibly deeper) parts of the reservoir into lower pressure zones. Gas and fluid exit points into the formation are unknown. Conventional production logs will be run to determine flow rates and exact water and gas entry points.

The fluid level in the 553-26B was above the slotted liner, and fluid entry into the wellbore could not be observed. A shallow casing leak with water entry and several holes in the casing were observed, which probably accounts for the high fluid level.

Application of video logging can be improved by determining fluid levels and shut-in surface pressures prior to running video logs. The wells should be shut in for a day or more before running the log so that the pressure buildup will push the fluid level down to mid-perf level. Gas and water may continue to flow from high pressure zones and may continue to enter low pressure zones. During the logging job, a first pass should be made down and then up during shut-in conditions. The camera should then be moved to the top of perforations and the flow line opened enough to begin bleeding off pressure (until hissing is heard). Gradual opening of the well should minimize movement of fines that may obscure visibility and should keep the fluid level from rising too rapidly. The well should then be logged downward until the fluid level is reached. Logging should not continue into the fluid-filled portion of the well unless the fluid was clear during shut-in condition. Once the fluid level has been reached, the flow rate can then be increased and the well logged upward ahead of the advancing fluid level.

Workstation and Modeling Software

The purchase and installation of the Silicon Graphics, Inc., workstation is complete. Chevron purchased a 200-MHz Indigo2 workstation with 1 MB cache memory, 256 MB RAM memory, Extreme Graphics card, 2 GB system disk, internal 4-mm DAT SCSI drive, internal 2X CD-ROM drive, and two 20-in. monitors. An external 9GB disk drive is on order. The external drive is necessary to install Landmark's StrataModel software for three-dimensional model building and visualization. Chevron paid for the drive because of anticipated needs for other software to enhance the functionality of the workstation for mapping, cross-section building, and geostatistics. All of these products should work together to provide state-of-the-art geologic computer functionality.

DESIGN AND IMPLEMENTATION OF A CO_2 FLOOD UTILIZING ADVANCED RESERVOIR CHARACTERIZATION AND HORIZONTAL INJECTION WELLS IN A SHALLOW-SHELF CARBONATE APPROACHING WATERFLOOD DEPLETION

Contract No. DE-FG22-94BC14991

Phillips Petroleum Company
Odessa, Tex.

Contract Date: June 3, 1994
Anticipated Completion: Jan. 2, 2001
Government Award: $2,659,515

Principal Investigator:
John F. Chimahusky

Project Manager:
Jerry Casteel
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objectives

The first objective is to use reservoir characterization and advanced technologies to optimize the design of a carbon dioxide (CO_2) project for the South Cowden Unit (SCU), Ector County, Tex. The SCU is a mature, relatively small, shallow-shelf carbonate unit nearing waterflood depletion. The second objective is to demonstrate the performance and economic viability of the project in the field. This report includes work on the reservoir characterization and project design objective and the demonstration project objective.

Summary of Technical Progress

Phase I

Evaluation of Surfactants Adsorption

Previous adsorption studies with SCU cores performed in the laboratory indicated a strong dependency of surfactant adsorption on core porosity. In an effort to rank the best two surfactants (Phodapex CD-128 and Chaser CD-1045) for the SCU CO_2–foam applications, Baker Dolomite cores (which are quite uniform) were selected. Ten adsorption tests were performed in Baker Dolomite cores in the absence of crude oil. Each core was flooded with 1000, 2000, or 3000 ppm surfactant. A total of 30 mg of surfactant was injected in each core test, followed by sufficient amount of synthetic SCU brine. The core effluents were monitored with a Waters Model 410 Differential Refractometer. The surfactant concentration in the effluents was also determined by measuring the total organic carbon (TOC). Average surfactant adsorptions for CD-1045 measured at 10 PV by refractive index (RI) and TOC are 419 and 425 lb/acre-ft, respectively. Average surfactant adsorptions for a Phodapex CD-128 are 81 lb/acre-ft (RI) and 93 lb/acre-ft (TOC).

Technology Transfer

A poster session entitled "Reservoir Characterization of an Upper Permian Platform Carbonate in Preparation for a Horizontal-Well CO_2 Flood, South Cowden Unit, West Texas" was presented at the Oklahoma Geological Society/U.S. Department of Energy Symposium, "Platform Carbonates in the Southern Midcontinent," Oklahoma City, Okla., March 26–27, 1996.

The Society of Petroleum Engineers Permian Basin Oil & Gas Recovery Conference held March 27–29, 1996, in Midland, Tex., included a poster session entitled "Construction of a 3-D Geologic Reservoir Description from Core and Well Log Data, South Cowden Field CO_2 Project." A technical paper, SPE 35226, *Use of Production and Well Test Data with Predictive History Matching to Improve Reservoir Characterization for CO_2 Flooding at the South Cowden Unit,* was also presented. This paper presented the approach used in the South Cowden project to improve the delineation of the porosity and permeability distribution in the reservoir by integrating production performance data with three-dimensional (3-D) geological modeling and predictive history matching techniques.

Phase II

Reservoir Simulation

The South Cowden full-field simulation model was expanded and updated to accommodate revised reservoir description information resulting from (a) inclusion of data from five additional wells drilled in the project area and (b) improvements in delineation of the porosity and permeability distribution in the project area by integration of production performance data with 3-D geological modeling. The field performance history match was updated with the use of the revised model. This resulted in significant improvements in individual well performance matches.

The revised simulation model was used to update CO_2-flood performance forecasts and to optimize final horizontal well locations, orientation, and completion strategy. On the basis of the revised forecasts, the western horizontal well (SCU 7CllH) was reoriented to conform to local reservoir quality trends. Simulation model forecasts indicate that this should result in more rapid production response to CO_2 injection. The revised project performance forecasts were also used in final design of surface facilities and in finalization of well conversion and workover strategies prior to implementation of CO_2 injection.

Well Drilling

The drilling and completion plans for the two horizontal injectors were completed after the final well locations were determined. The first horizontal well, SCU 6C25H, was spudded on Mar. 17, 1996. Land purchase for the project area was completed in January 1996. Surface injection facility construction was begun in February 1996.

Petrographic Study of Core from SCU 6-24

The burrow mottled dolopackstones that make up the SCU reservoir interval are gray, relatively low-porosity and low-permeability dolowackestones/dolopackstones and tan, oil-stained, more porous and permeable dolopackstones/dolograinstones. Tan dolomite areas are burrows. Interburrow areas are lower porosity gray dolomite. The relative amounts of gray and tan dolomites making up the SCU reservoir interval markedly affect the reservoir porosity and permeability. A clear Mylar™ sheet with a 1-in.-square grid pattern was used to determine the relative amounts of gray and tan dolomites that make up the reservoir interval in the SCU 6-24 core. These amounts, determined for each 1-ft interval of the Grayburg reservoir, will be compared with gray/tan percentages similarly determined for the SCU 8-19, 7-10, 6-23, and 8-11 cores.

Reservoir porosity is also a function of anhydrite content. Thin-section study of burrow mottled dolopackstones from the SCU 8-19, 7-10, 6-23, and 8-11 and the Moss Unit 16-14 shows that as anhydrite content increases reservoir porosity decreases. Thin-section study of reservoir dolomites from the SCU 6-24 confirms these findings. Average anhydrite content of tan dolomites (determined from this sections) and average porosities (determined from core analysis) are given in Table 1.

Anhydrite content in the lower part of the reservoir interval in the SCU 6-24 (zone E below 4675 ft, log depth) averages less than 1% anhydrite. Porosity estimated from thin section for this interval is approximately 12%. Zones E and F above 4675 ft average 19% anhydrite and 4.5% porosity, as determined from thin section (porosities estimated from thin section are typically lower than those determined by core analysis).

TABLE 1

Average Anhydrite Content and Average Porosities of Tan Dolomites

Well	Average anhydrite, %	Average porosity, %
SCU 8-19	1	24
SCU 6-23	1	21
SCU 7-10	5	21
SCU 8-11	11.5	14.5
Moss 16-14	15.5	6

Tan dolomite areas have varying permeabilities related to pore size. Tan dolomites with similar porosities may have markedly different permeabilities. The average porosity of tan dolomites from SCU 6-23 and 7-10 is 21%, but the average permeabilities are 90 and 10 mD, respectively. Tan dolomites from SCU 7-10 have markedly smaller pores and finer dolomite crystal size than tan dolomites from SCU 6-23. Tan dolomite samples from SCU 6-24 vary markedly in crystal size and consequent pore size, resembling samples from both SCU 7-10 and 6-23.

CO_2 HUFF 'N' PUFF PROCESS IN A LIGHT OIL SHALLOW-SHELF CARBONATE RESERVOIR

Contract No. DE-FC22-94BC14986

Texaco Exploration and Production Inc.
Midland, Tex.

Contract Date: Feb. 10, 1994
Anticipated Completion: Dec. 31, 1997
Government Award: $347,493

Principal Investigators:
Scott Wehner
John Prieditis

Project Manager:
Jerry Casteel
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The principal objective of the Central Vacuum Unit (CVU) carbon dioxide (CO_2) Huff 'n' Puff (HnP) project is to determine the feasibility and practicality of the technology in a waterflooded shallow-shelf carbonate environment. The results of parametric simulation of the CO_2 HnP process coupled with the CVU reservoir characterization components will determine if this process is technically and economically feasible for field implementation.

Summary of Technical Progress

Field Demonstration

CVU No. 97 was returned to active status under flowing conditions on Dec. 27, 1995. Flowing tubing pressure averaged 631 psig with choke settings between $^{13}/_{64}$ and 18/64 in. Initially, production averaged 901 thousand cubic feet of gas per day (MCFGD). Gas production cannot exceed 1000 thousand standard cubic feet per day (MSCFGD) because of disposal limitations. No appreciable water production was seen initially. Compositional analyses of the gas stream show that early gas rates were at 94% CO_2. Current production is at 70% CO_2. Liquid hydrocarbon production was initially too small to measure and began increasing on the third day. Samples are being collected and retained. The fluid was initially a transparent straw color (41 °API), which suggests that lighter hydrocarbons are being affected (or paraffins and asphaltenes are being left behind). The well is currently producing the field normal 35 °API crude. The well had achieved a 70 bbl of oil per day (BOPD) rate by the 10th net day of flow-back (average predemonstration was 68 BOPD). Production has been volatile. The well initially flowed on various choke settings but eventually loaded up. An electric spontaneous potential was run into the wellbore in early March 1996. Following some minor operational problems, the well peaked at 184 BOPD; however, production has declined sharply following this peak. Approximately 100% of the injected CO_2 volume has been produced. The well continues to produce high gas volumes. Therefore the accuracy of either the test volumes or compositional analysis or a combination of both is suspect. One notable benefit to date is a reduced volume of water production which has a strong impact on lifting costs. Figure 1 contains the field demonstration history through mid-May 1996.

Site-Specific Simulation

A need for model refinement has been demonstrated by the differences between predictions and early results (injection rates, pressures, and production). Monitoring of the CVU field demonstration continues. Early results do not provide enough data to make an informed opinion; the project continues under nervous optimism. Over the next several months, production will be monitored and history matched with the compositional simulator. The mechanisms investigated during the parametric simulation exercise will be incorporated as warranted. Pursuit of a second demonstration site will be weighed, and findings will be developed during the history matching.

If the demonstration is successful, guidelines for the cost-effective selection of candidate sites will be developed along with an estimation of the recovery potential. The economics of the process, if positive, will also be provided.

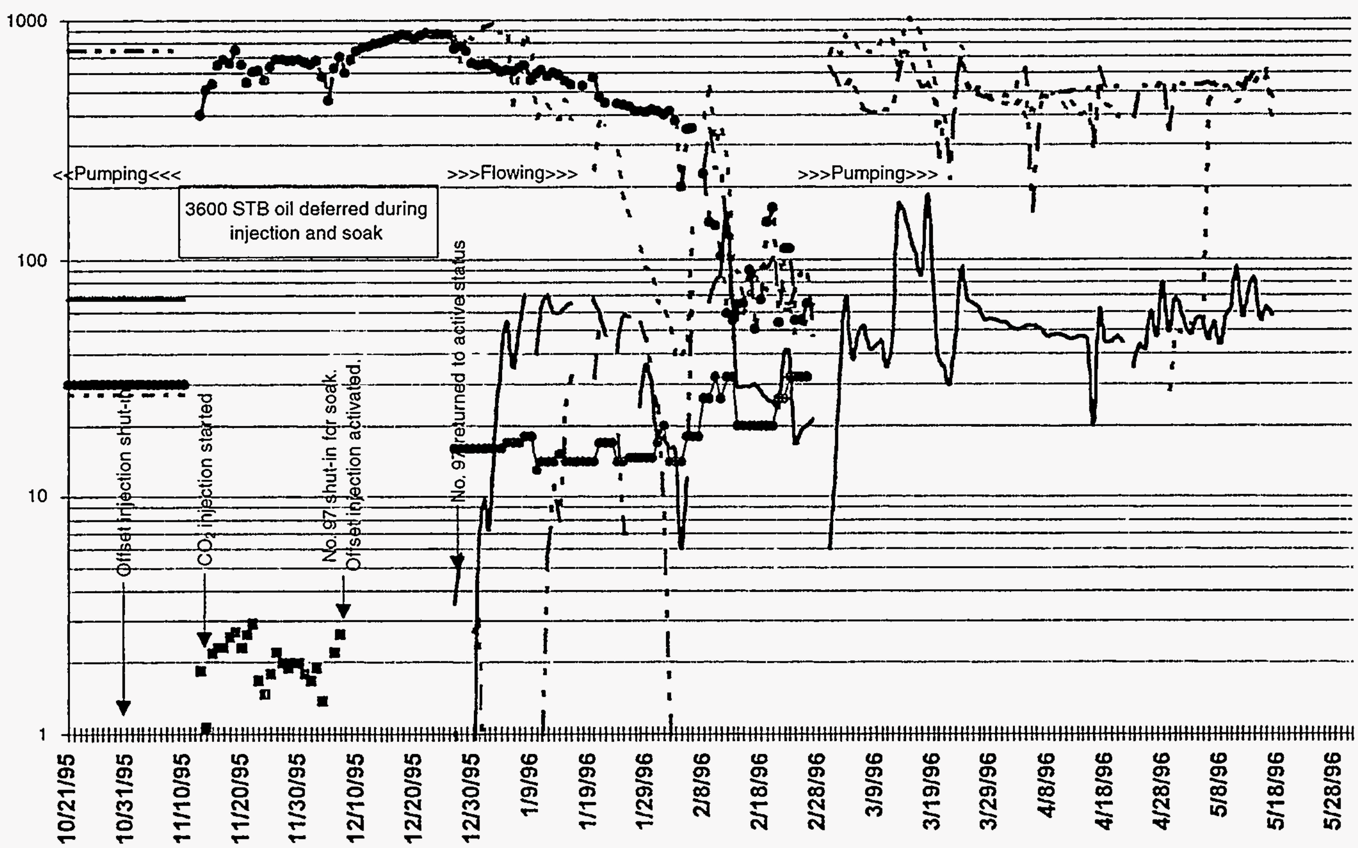


Fig. 1 Field demonstration data through mid-May 1996. —, oil (stock tank barrels per day). — - -, water (bbl/d). - - -, total gas (thousand cubic feet per day). ■, CO_2 injection (million cubic feet per day). —• -, Tbg. pressure (pounds per square inch gage). —•—, choke.

Technology Transfer

The Petroleum Recovery Research Center continues to provide updates on the project in its quarterly newsletter. Also the newly formed Petroleum Technology Transfer Council is providing complete quarterly and annual technical reports on a industry bulletin board called GO-TECH to provide timely dissemination of information to those interested.

Abstracts were accepted and manuscripts presented at the Society of Petroleum Engineers' (SPE) Permian Basin Oil and Gas Recovery Conference (March 1996). A technical paper (SPE 35223) was published in the conference's proceedings.

REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY–SUNSET FIELD, SAN JOAQUIN BASIN, CALIFORNIA

Contract No. DE-FC22-95BC14937

University of Utah
Salt Lake City, Utah

Contract Date: June 14, 1995
Anticipated Completion: Mar. 13, 2000
Government Award: $637,891.00
(Current year)

Principal Investigator:
Steven Schamel

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1– Mar. 31, 1996

Objective

The objective of this project is to reactivate ARCO Western Energy's idle Pru Fee lease in Midway–Sunset field in California and conduct a continuous steamflood enhanced oil recovery (EOR) demonstration aided by an integration of modern reservoir characterization and simulation methods. Cyclic steaming will be used to reestablish baseline production within the reservoir-characterization phase of the project. During the demonstration phase, a continuous steamflood EOR will be initiated to test the incremental value of this method as an alternative to cyclic steaming. Other economically marginal Class III reservoirs with similar producibility problems will benefit from insight gained in this project. The objectives of the project are to (1) return the shut-in portion of the reservoir to commercial production; (2) describe accurately the reservoir and recovery process; and (3) convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.

Summary of Technical Progress

Two main activities were completed during the first quarter of 1996: (1) lithologic and petrophysical description of the core taken from the new well Pru 101 near the center of the demonstration site and (2) development of a stratigraphic model for the Pru Fee project area. In addition, the first phase of baseline cyclic steaming of the Pru Fee demonstration site was continued with production tests and formation temperature monitoring.

Lithologic and Petrophysical Description of Pru 101 Core

A new well was drilled, cored, and logged in October 1995. That same month the core was described and samples were collected for analysis. The report on the core was completed in January 1996 by ARCO Exploration and Production Technology (Plano, Tex.). In addition to visual core description the analysis included petrophysical properties, textural analysis of the sand, and X-ray diffraction and thin-section descriptions. Petrophysical analysis of the reservoir included refinement of a Monarch sand log model for calculation of porosity, permeability, and saturations with the use of a suite of logging tools (array induction imager, litho-density, compenstated neutron, and gamma ray) or any other Monarch well with a resistivity, density, and neutron log. The report addressed questions of reservoir architecture and performance through projections of sand and barrier continuity and overall reservoir quality.

A total of 225 ft of core was recovered from the Pru 101 well, which represents approximately 85% recovery from the interval cored. A full 96% of the core recovered from the Monarch sand consists of oil-stained sand divisible into four lithofacies: 27% medium-grained sand, 43% coarse-grained sand, 16% granule sand, and 10% pebble sand. The remaining 4% of the core is comprised of nonreservoir mudstone and muddy to bioturbated fine sand. The only interval in the Monarch that may be a laterally continuous steam barrier is from a depth of 1208 to 1218 ft. As interpreted from the log response, this interval is likely composed of interbedded muddy fine sand and medium-grained oil sand, although no core was recovered through it.

The cored interval through the Monarch sand consists of major fining-upward sequences. A typical sequence begins with a pebble or granule sand that progresses upward through coarse-grained sand, medium sand, and perhaps interbedded bioturbated or muddy sand before passing abruptly into another pebble or granule sand that begins the next sequence. Overall, however, the full section from the oil–water contact to the top of the Monarch (1106.4 to 1368.6 ft) coarsens upward, which is consistent with a prograding shoreline and progressive filling of the basin. The proposed depositional model is a steep-faced fan-delta prograding onto a shallow marine shelf. Periodic remobilization of fan-delta deposits as debris flows generate slumps and turbidity currents that deposit the Monarch sand. The muddy fine sands capping many of the turbidites are deposited from suspension as the flow wanes. The absence of any true marine clays indicates short periods between successive debris flows and turbidites.

The Monarch sand in the Pru 101 core is dominantly thin bedded. The lower part of the core, above the oil–water contact, consists of stacked, thin-bedded, highly graded (fining up) coarse to medium sand. Overlying the thin-bedded units is a zone of pebble sand beds that contain matrix-supported cobbles. The upper part of the core consists predominantly of highly graded (fining up) coarse sand. Although sand beds are generally thin (1 to 2 ft) throughout the core, they appear to be thickening upward.

Routine petrophysical analysis was conducted by CoreLab on 246 samples with the use of a confining pressure of 500 psi. The vertical variations in measured porosity, permeability, and oil saturation (S_o) are shown in Figs. 1 to 3. Medium-grained sands have the highest porosity (33.6%) as the result of the absence of pebbles. With the progressive inclusion of more pebbles, porosity decreases to 31.1% in coarse sands, 30. 0% in granule sands, and 28.5% in pebble sands. Granule and coarse-grained sands have the highest geometric mean permeabilities (about 2700 mD). Medium-grained sands are better sorted, but they have a lower mean permeability (1847 mD). Pebble sands also have a lower mean permeability (2082 mD) as the result of the poorer sorting. Two-thirds of the mudstones and one third of the bioturbated to muddy sands have permeabilities in the range of 18 to 27 mD, which are at least two orders of magnitude lower than productive sands. This should be sufficient to make these fine-grained, clay-rich rocks barriers to vertical steam migration if they are sufficiently thick and laterally continuous.

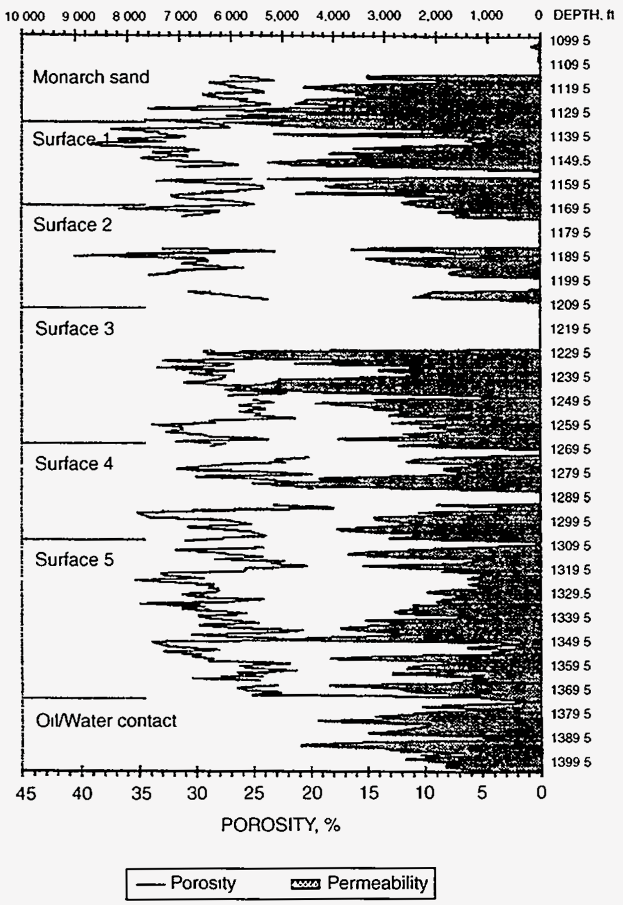


Fig. 1 Measured porosity and permeability in Pru 101 core.

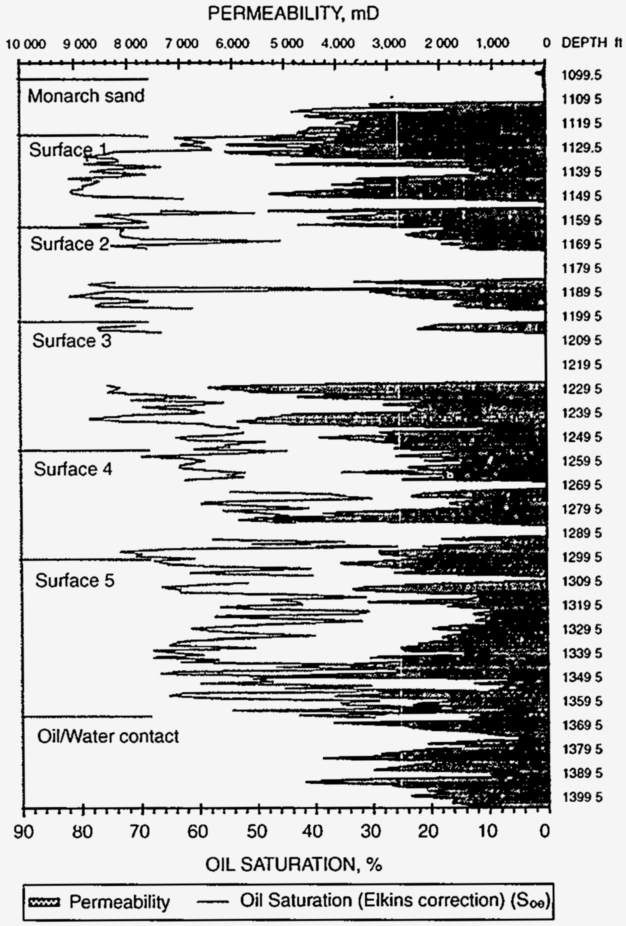


Fig. 2 Measured oil saturation and permeability in Pru 101 core.

The water saturation (S_w) and S_o measurements from the core are of limited reliability as the result of the drainage of fluids from the samples, possible invasion during coring, and transition-zone penetration. Nevertheless, the (S_w) minimums are instructive—16% in coarse and granule sand, 18% in medium sand, and 20% in pebble sand. These values follow the same trend as permeability distribution and provide a measure of irreducible water saturation (S_{wirr}). Similarly, the S_o minimums of about 13% provide a measure of the residual oil saturation (S_{or}) to steamflooding.

A log analysis model for the Monarch sand on the Pru Fee property was developed to calculate effective porosity, permeability, water saturation, nonreservoir volume, and pebble volume from any well with a minimum log suite of resistivity, density, and neutron curves. Although the model was calibrated to the core analyses from the Pru 101 well, it was applied to the nearby Pru 533 well for additional verification. The log curves from Pru 101 and Pru 533 indicate that resistivities less than about 13 Ω-m are nonreservoir. These intervals contain both silty sands and higher quality wet sands.

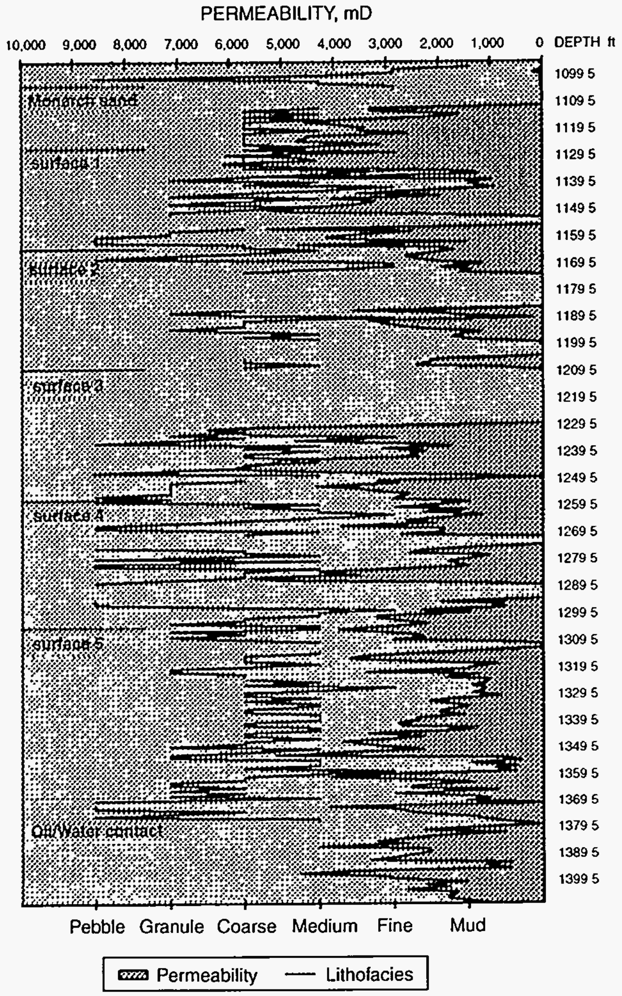


Fig. 3 Permeability and lithotype observed in Pru 101 core.

Stratigraphic Model

The Midway–Sunset field produces from multiple reservoirs that range in age from Oligocene to Pleistocene; most of the oil is produced from the upper Miocene reservoirs.[1] The reservoir at the ARCO Western Energy Pru Fee property is the upper Miocene Monarch sand.

The stratigraphic nomenclature applied to this part of the Midway–Sunset field is a combination of formal units, which are recognized at the surface and in the subsurface, and informal units, which are identified mostly in the subsurface. The stratigraphic nomenclature of Callaway[2] and Foss and Blaisdell,[3] which is the nomenclature in most common use in the field, has been adopted in this project. The Monarch sand is an informal unit within the Antelope shale member of the Monterey shale (Fig 4). It typically overlies the informal Republic, Williams, and Leutholtz sands (in descending order). The Monarch sand normally is overlain by the upper part of the Antelope shale and the Reef Ridge shale. At the location of the Pru Fee property on the southwest flank of the Spellacy anticline, however, a regional unconformity removes the Reef Ridge shale and the top of the Antelope shale, which places the Pliocene Etchegoin formation directly on the Monarch sand. Although no well has penetrated below the Monarch sand at the project area, there is reason to believe that the underlying stratigraphic section is similar to that of nearby areas.

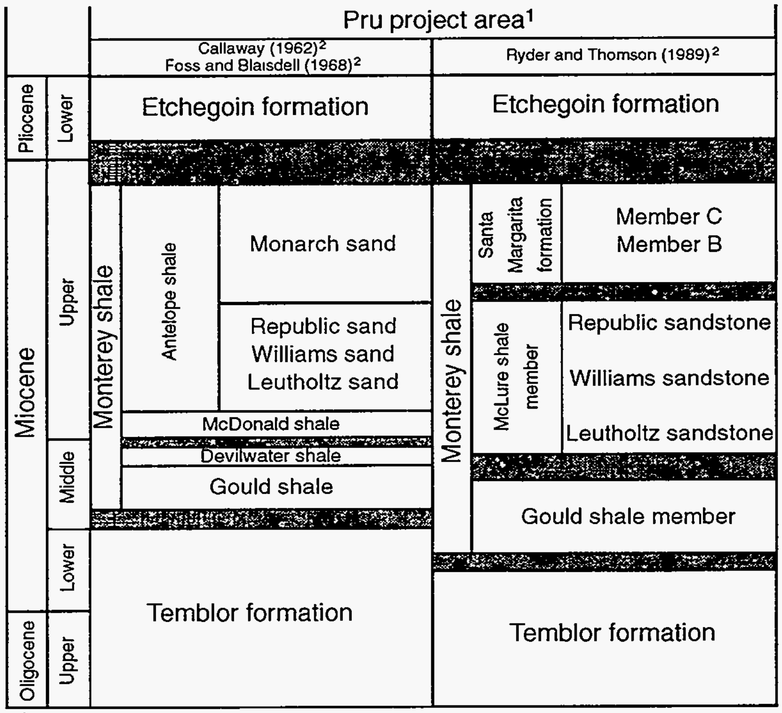
The stratigraphic model for the Monarch sand reservoir in the project area was developed with the use of geophysical logs, core descriptions, outcrop observations of comparable units, and petrophysical data from core plugs. There are 143 wells in the project area, of which 33 are within the Pru Fee property. About 80% of the log suites were suitable for identifying and correlating stratigraphic units within the Monarch sand; however, there were only three cores available in this phase of the project, ARCO wells Pru 101, Pru 533, and Kendon 405 located immediately west of the Pru property. All three cores have quality lithologic descriptions and petrophysical data.

Stratigraphic divisions recognized in the Pru 101 and Pru 533 cores and reflected in log response, particularly in conductivity, deep resistivity, and gamma-ray logs, were correlated throughout the project area. Five surfaces could be correlated with a reasonable degree of confidence between most of the wells (Fig. 5). At least two of the surfaces (1 and 3) appear to correspond to laterally continuous or semicontinuous nonreservoir units that might serve as a barrier or baffle to steam injection

Surfaces 1, 2, and 3 were recognized in all wells; however, surfaces 4 and 5 were not. The lithologic assemblage, grain size, bed thickness, and other sedimentologic features of the stratigraphic unit between surfaces 4 and 5 in the Pru 101 well suggest that it was deposited as a debris flow or series of debris flows. An irregular zone of debris flows (marked by top of the highest and base of the lowest debris flow) occupies the middle to lower part of the interval between surface 3 and the oil–water contact. Although a concentration of debris flows is found in this zone, individual debris flows are located elsewhere in the core.

The thickness of the Monarch sand gross pay (top of Monarch to the oil–water contact) decreases southeastward across the project area from about 440 ft in the northwest to less than 100 ft in the southeast (Fig. 6). This trend also is reflected in the thickness patterns of the individual stratigraphic units. A dip cross section (B-B′) shows that most stratigraphic units thin to the southeast (Fig. 7). A strike (southwest to northeast) cross section shows limited variations in unit thickness, however (Fig. 8). Local thinning of some flow units in the northern part of the project area may reflect paleotopography. The unusual contour pattern in the southeastern part of the gross pay contour map (Fig. 6) reflects limited well control in this area.

The Monarch sand within the project area, which is on the southwest flank of the Spellacy anticline, is gently folded by a low-amplitude syncline that plunges southeastward. The top of the Monarch is about 440 ft above sea level in the northwestern part of the project area and about 100 ft above sea level in the southeastern part.



1 The Monarch sand is the oldest formation penetrated in the Pru project area
2 Modified for the Pru project area.

Fig. 4 Stratigraphic nomenclature for Midway–Sunset field.

Activities at the Pru Fee Demonstration Site

During the early part of this quarter, all major work at the Pru Fee site was successfully implemented, except for the casing vapor collection system (CVCS) installation and gathering line upgrade. These two actions were deferred pending evaluation of need.

The first phase of baseline cyclic steaming, which began in the last quarter of 1995, was continued during this quarter. During the first round, 70,000 bbl of steam was injected into 9 wells near the center of the Pru Fee property. Production peaked at about 90 bbl/d shortly after the close of the first round, but within a period of weeks had dropped back to about 70 bbl/d. Production was dominantly from the new Pru 101 well. The lower than expected flow rates from the refurbished older wells is attributed to completion problems that will be investigated in subsequent steam cycles. Two of the older wells came back cold immediately after steaming, which indicates a problem with either steam allocation among the several wells in the text or loss of steam to upper stratigraphic intervals.

The initial steam cycle demonstrated the need to better monitor both the flow of steam to individual wells and the penetration of steam into the reservoir at each well. The second round of steaming was begun under closer monitoring. This has involved injecting one well at a time and surveying the formation intervals penetrated with the use of radioactive tracers. The second round of cyclic steaming (part of the first scheduled phase of baseline testing) was in progress when the quarter ended.

The temperature observation (TO) well near the center of the cluster of test wells indicated heating at the top of the Monarch sandstone at the end of the first round of steaming. Temperature did not increase in other segments of the TO well, probably because of the relatively small volume of steam injected during the first round. The heating observed in the Tulare formation at about 500 ft depth may be due to leakage through poor primary cement in one of the older wells.

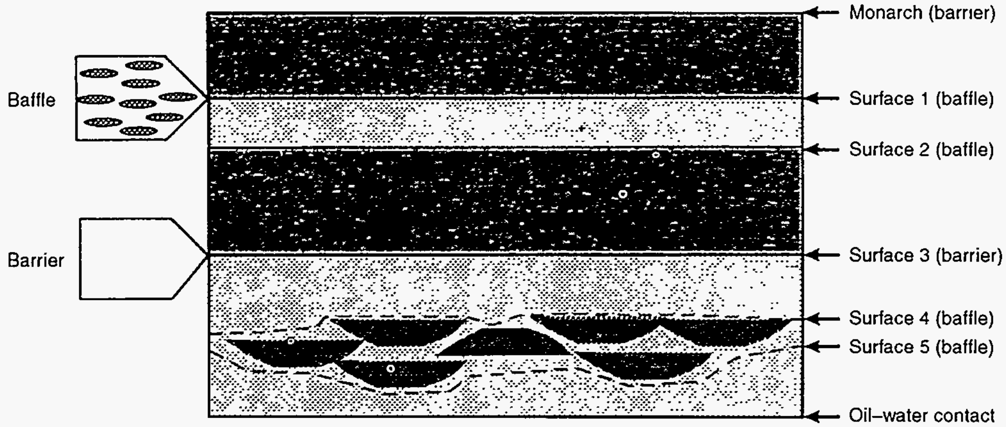


Fig. 5 Generalized stratigraphy of the Monarch sand reservoir.

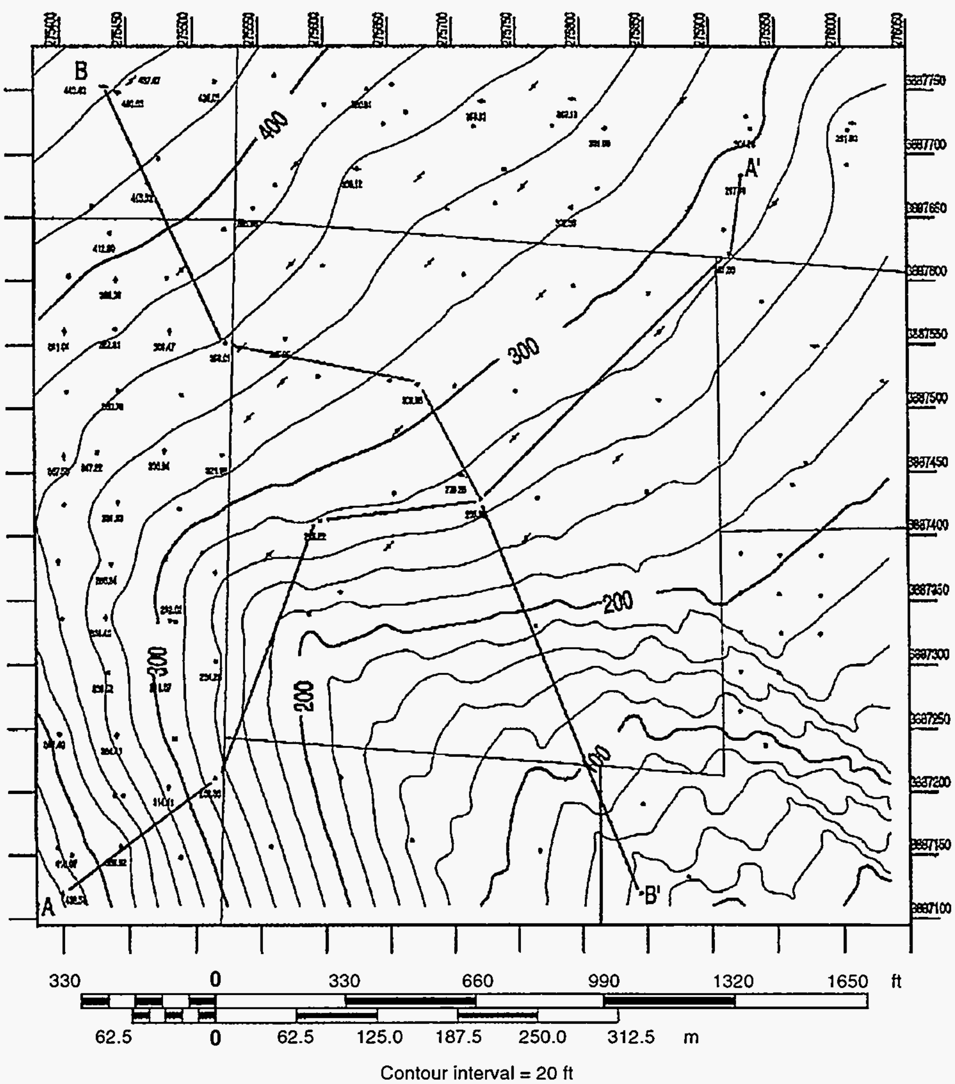


Fig. 6 Contour map of gross pay of Monarch sand at Pru project area. (Art reproduced from best available copy.)

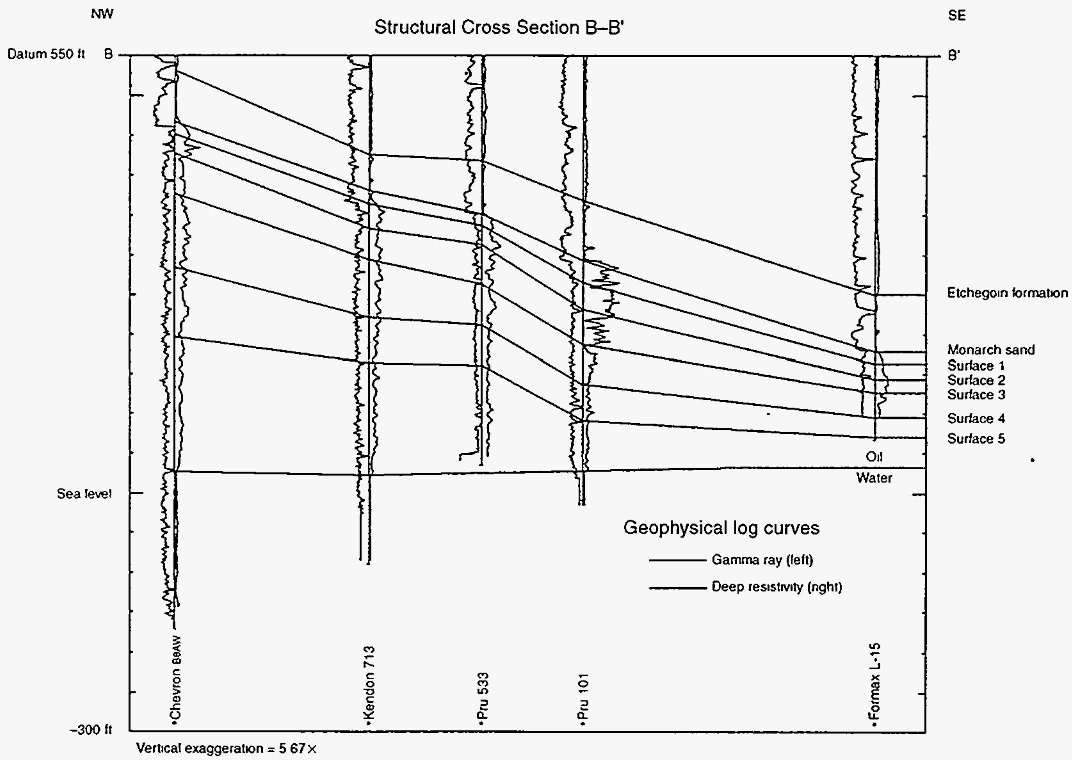


Fig. 7 Dip section through Pru project area (refer to Fig. 6). (Art reproduced from best available copy.)

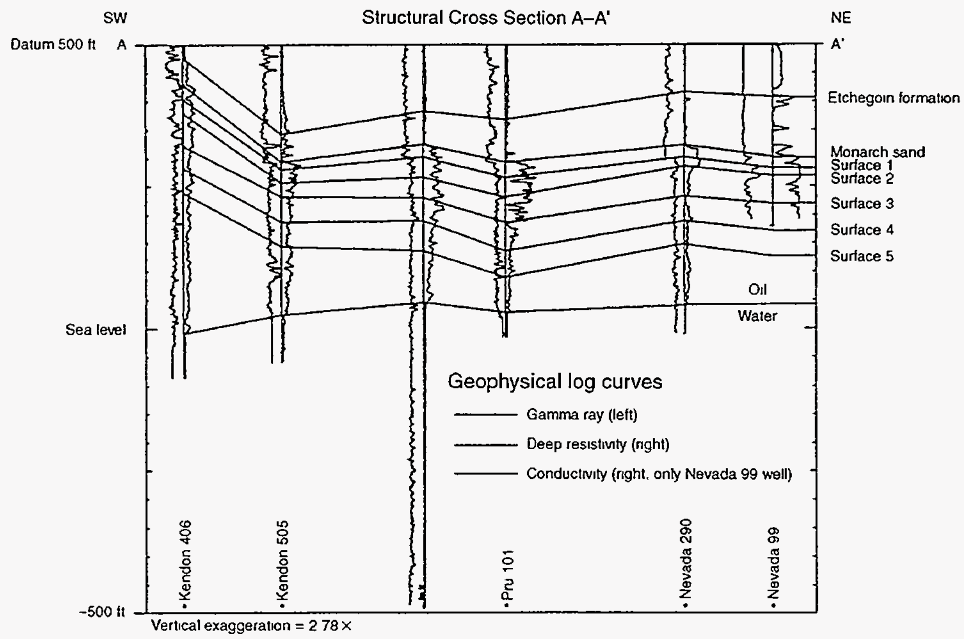


Fig. 8 Strike section through Pru project area (refer to Fig. 6).

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2. D. C. Callaway, *Distribution of Upper Miocene Sands and Their Relation to Production in the North Midway Area, Midway Sunset Field, California*, selected papers: San Joaquin Geological Society, Vol. 1, pp. 47-55, 1962.
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GEOLOGICAL AND PETROPHYSICAL CHARACTERIZATION OF THE FERRON SANDSTONE FOR THREE-DIMENSIONAL SIMULATION OF A FLUVIAL–DELTAIC RESERVOIR

Contract No. DE-AC22-93BC14896

Utah Geological Survey
Salt Lake City, Utah

Contract Date: Sept. 29, 1993
Anticipated Completion: Sept. 29, 1996
Government Award: $633,650
(Current year)

Principal Investigator:
M. Lee Allison

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1996

Objective

The objective of this project is to develop a comprehensive, interdisciplinary, and quantitative characterization of a fluvial–deltaic reservoir that will allow realistic interwell and reservoir-scale modeling to be used for improved oil-field development in similar reservoirs worldwide. The geological and petrophysical properties of the Cretaceous Ferron sandstone in east-central Utah (Fig. 1) will be quantitatively determined. Both new and existing data will be integrated into a three-dimensional (3-D) representation of spatial variations in porosity, storativity, and tensorial rock permeability at a scale appropriate for interwell to regional-scale reservoir simulation. Results could improve reservoir management through proper infill and extension drilling strategies, reduce economic risks, increase recovery from existing oil fields, and provide more-reliable reserve calculations. Transfer of the project results to the petroleum industry is an integral component of the project.

Summary of Technical Progress

Technical progress this quarter is divided into case-study evaluation, geostatistics, and technology transfer activities. The work focused on one parasequence set, the Kf-1, in the Willow Springs Wash and Ivie Creek case-study areas (Fig. 1). In the Ivie Creek case-study area, the Kf-1 represents a river-dominated delta deposit that changes from proximal to distal from east to west. In the Willow Springs Wash case-study area, the Kf-1 contains parasequences that represent river-dominated and wave-modified environments of deposition. Interpretations of lithofacies, bounding surfaces, and other geologic information are being used to determine reservoir architecture. Graphical interpretations of important flow boundaries in the case-study areas, identified on photomosaics, are being used to construct cross sections, paleogeographic maps, and reservoir models. Geostatistical analyses are being incorporated with the geological characterization to develop a 3-D model of the reservoirs for fluid-flow simulation. Technology transfer consisted of setting up a home page on the Internet and presenting project benefits to the public.

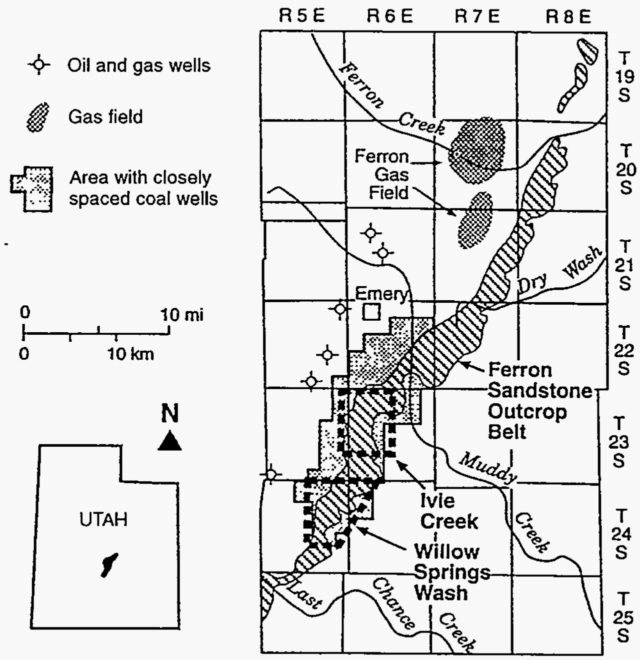


Fig. 1 Location map of the Ferron sandstone outcrop belt (cross-hatched) showing case-study areas (outlined in heavy dashed lines).

Case-Study Evaluation

Willow Springs Wash

Methods. Work during the quarter consisted of processing and interpreting the data collected from the Indian Canyon portion of the area during the previous field seasons. Particular attention was paid to the development of depositional models for the Kf-1–Indian Canyon-c and Kf-1–Indian Canyon-d parasequences. The collected data were compared with models developed from nonbarred and barred, wave-dominated shorelines and shorelines with varying amounts of tidal influence. On the basis of the conclusions from these efforts, paleogeographic maps were constructed that illustrate the evolution of depositional environments within the case-study area.

Interpretation. The Indian Canyon-c has been interpreted as a wave-modified shoreline. A tidal inlet developed during early deposition of the parasequence. Later, as longshore currents caused the inlet to migrate toward the southeast, deposition along a wave-dominated shoreline became the dominant process. Seaward of this tidal inlet, a thick section of dominantly seaward-oriented trough or tabular cross-stratification overlain by a thinner section of landward and more randomly oriented cross-stratification implies that modification of this model might be warranted. Work on nonbarred coasts by Clifton et al.[1] suggests that, as waves approach a shoreline, the sequence of sedimentary structures that develops includes a section of landward-oriented crossbeds. This is the opposite of what is seen in Indian Canyon. Hunter et al.[2] described deposits of barred shorelines displaying a significant seaward-oriented, crossbedded section. Seaward-oriented bedforms, in this case, represent deposition on rip-channel mouth bars or within longshore troughs. Evidence of repeated scour and fill, developed as rip channels migrated along the shoreline, would help to confirm this. This type of scour and fill has not been observed.

Another possible model for these deposits is an ebb-tidal delta. Ebb tides would account for the seaward-oriented crossbeds within Indian Canyon exposures. Additionally, a smaller section of landward-oriented crossbeds present above this, and below the foreshore deposits, could be explained by the presence of swash bars associated with the ebb-tidal delta. This model implies generally higher tidal ranges for the Ferron Sandstone however, Hays (verbal communication, 1996) has shown that tidal ranges fluctuate because of coastal geomorphology and are accentuated within bights or embayments. Ryer and McPhillips[3] suggested that such a bight was present along the Ferron coastline at this time. Further, Walther's law requires that the spatial association of the seaward oriented trough cross-stratification with a known tidal inlet be incorporated in the depositional model. An ebb-tidal delta model incorporates all these constraints.

Preservation of ebb-tidal deltas is relatively rare in modern environments. Some authors suggest that preservation of ebb-tidal deltas is greater along prograding shorelines.[4] It is certain that this shoreline prograded, and the upward- and seaward-stepping parasequence architecture suggests that sedimentation was overwhelming sea-level rise.

Realistically, a hybrid of both models may have produced the observed features in Indian Canyon. Slight differences in the depositional model may affect hydrocarbon reservoir potential, but there may not be enough evidence to eliminate either model.

Ivie Creek

Methods. Work during the quarter consisted of applying lithofacies names to the Kf-1–Ivie Creek-a parasequence in the amphitheater area to be used for paleogeographic interpretation and the detailed reservoir modeling exercise. Scaled line work on photomosaics for this area shows offlapping packages of beds (clinoforms). Most of the clinoforms boundary lines on the photomosaics were based on data from measured sections (i.e., unit boundaries) or changes in permeability as noted from the permeability transacts. Where a visual (and qualitative) change in permeability corresponding to a line on the mosaic and a unit boundary in a measured section is present, the line was highlighted. If these conditions were not met, the line was not highlighted. An estimated 80% or more of the lines on the interpreted mosaic were marked in yellow in the area of a measured section.

Two other higher order lines were also delineated. A line was marked where the tops of the clinoforms are truncated by erosion surfaces that extend for more than 300 ft laterally. These erosion surfaces drop stratigraphically through the Kf-1–Ivie Creek-a and the separate distal facies eventually become unrecognizable. The lines marking the tops of the clinoforms delineate larger packages of similar internal clinoform organization informally called subcycles.

Another highlighted line was used to designate a similar hierarchical package of rock or subcycle with a different upper bounding surface. In this case, the clinoforms do not appear to have been substantially eroded at the top. In the most proximal position, the bounding surface is overlain and underlain chiefly by sandstone. Progressing in a down-depositional direction, the lithology overlying the bounding surface becomes more shale dominated and a slope former on outcrop. In its most distal portion, this surface drops stratigraphically to a position within the lower third of bedding planes similar to the termination position of the other subcycle packages.

Interpretation. With the line work in place and an integration of measured sections, permeability data, and line work and associated annotations, the clinoform section of Kf-1–Ivie Creek-a parasequence was classified into four lithofacies: clinoform proximal (cp), clinoform medial (cm), clinoform distal (cd), and clinoform cap (cc). Lithofacies cp, cm, and cd are assigned to clinoforms only, and lithofacies cc is a bounding facies above the clinoforms (Fig. 2).

Lithofacies cp is mostly fine- to medium-grained sandstone. The chief-sedimentary structure is low-angle cross-stratification with minor horizontal and trough cross-stratification and rare hummocky bedding. The lithofacies is dominantly thick- to medium-bedded, well to moderately indurated, with permeabilities ranging from 2 to 600 mD and a mean of about 10 mD. The inclination of bed boundaries is generally greater than 10°. This lithofacies is interpreted to be the highest energy and most proximal to the sediment input point. The steep inclinations are interpreted to represent deposition into a relatively localized deep area in an open bay environment. The dominance of low-angle cross-stratification with inclination within the bed or clinoforms in an updepositional dip direction indicates the influence of onshore wave energy.

Lithofacies cm is dominantly sandstone with about 5% shale. The sandstone is primarily fine grained with slightly more fine to very fine grained than fine to medium grained. Horizontal beds dominate with some rippled, trough, and

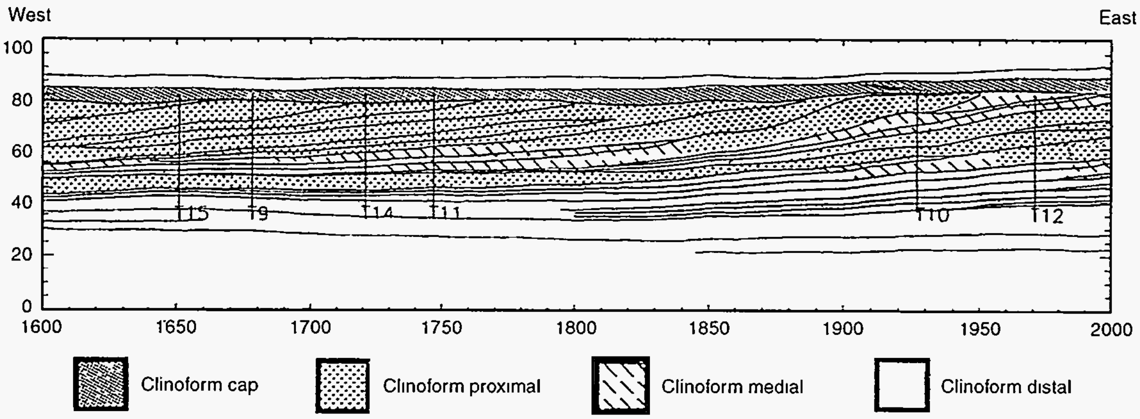


Fig. 2 Scaled cross section, based on a portion of the Ivie Creek photomosaic, showing clinoform lithofacies assigned to the Kf-1–Ivie Creek-a parasequence. Vertical lines represent permeability transect locations.

low-angle cross-stratification. Bed thicknesses range from laminated to very thick, but most are medium. The beds are generally well to moderately indurated but are occasionally friable. The permeability values range from nondetectable to 100 mD with mean about 3 mD. Inclination on the clinoform boundaries is between 2° and 10°. Lithofacies cm is generally transitional between lithofacies cp and cd but occasionally is present at the erosional truncation or offlapping boundary of the clinoforms with no visible connection to lithofacies cp.

Lithofacies cd is sandstone (sometimes silty) with about 10% shale. The sandstone grain size is dominantly fine to very fine grained with considerable variation. Sedimentary structures in this lithofacies are chiefly horizontal laminations and ripples in medium to thin beds. Induration of the beds ranges from well to friable. Average lithofacies cd permeability is just at the detection limit of 2 mD but ranges up to 80 mD. This lithofacies is gradational with lithofacies cm and represents the deepest water and lowest energy deposition within the clinoform. It can be traced distally into prodelta to offshore.

Lithofacies cc consists of very-fine- to fine-grained, thick- to medium-bedded sandstone. The beds are horizontal with some trough and low-angle cross-stratification. Burrowing is rare. The sandstone is mostly well indurated with permeabilities ranging from nondetectable to 100 mD and a mean of about 2 mD. This lithofacies is present stratigraphically above the truncated clinoforms near the top of the parasequence and where bed boundaries show little to no inclination. The cc lithofacies is interpreted to represent an eroded and reworked delta top.

Figure 3 is a paleogeographic interpretation of the third step of the five depositional time steps of parasequence Kf-1–Ivie Creek-a. The main delta lobe was located to the east and northeast. That delta lobe allowed a protected embayment to develop in the northwest part of the case-study area. The clinoforms observed in section 16 (Fig. 2) represent deposition into the embayment fed by river channels to the southeast. The shoreface–delta front, shallow marine, and deep marine environments produced the clinoform proximal, medial, and distal lithofacies, respectively.

Geostatistics

Geostatistical work this quarter was devoted to the investigation of statistical relationships between geologic features and permeability data and among various geologic features. The analyses thus far have included only data for the Kf-1–Ivie Creek-a parasequence in the Ivie Creek case-study area. Permeability values exhibit log-normal distributions with respect to sedimentary structure and grain size and a less clear relationship with respect to bed size and induration. When grouped by clinoform lithofacies, permeability values exhibit a log-normal distribution where mean permeability value decreases with decreasing depositional energy (Fig. 4). Each clinoform lithofacies is characterized by a particular suite of geologic features, as shown in the summary plots of Fig 5. There are distinct relationships between depositional energy, sedimentary structure, average grain size, and lithology; weaker correlations exist for induration and bed size. The relative frequency of sedimentary structures was calculated for the four lithofacies (Fig. 5a). Horizontal bedding is the most common sedimentary structure in all lithofacies. Ripple cross-laminated beds are most common in the clinoform distal lithofacies (cd). Low-angle and trough cross-stratified beds are common only in the clinoform proximal lithofacies (cp). The grain-size distributions (based on megascopic observations) were also calculated for the four lithofacies (Fig. 5b). As one might expect, the clinoform proximal lithofacies contains the coarsest material and the clinoform distal lithofacies the finest. The proximal sandstones also contained the greatest variations in grain sizes.

Technology Transfer

The Utah Geological Survey (UGS) presented a brief overview of the geology and development activity of the Ferron sandstone coal bed methane fairway at a public information meeting on March 5, 1996, in the Emery County Courthouse at the request of the Emery County Planning Commission. A lecture, entitled "Geology and Gas Potential

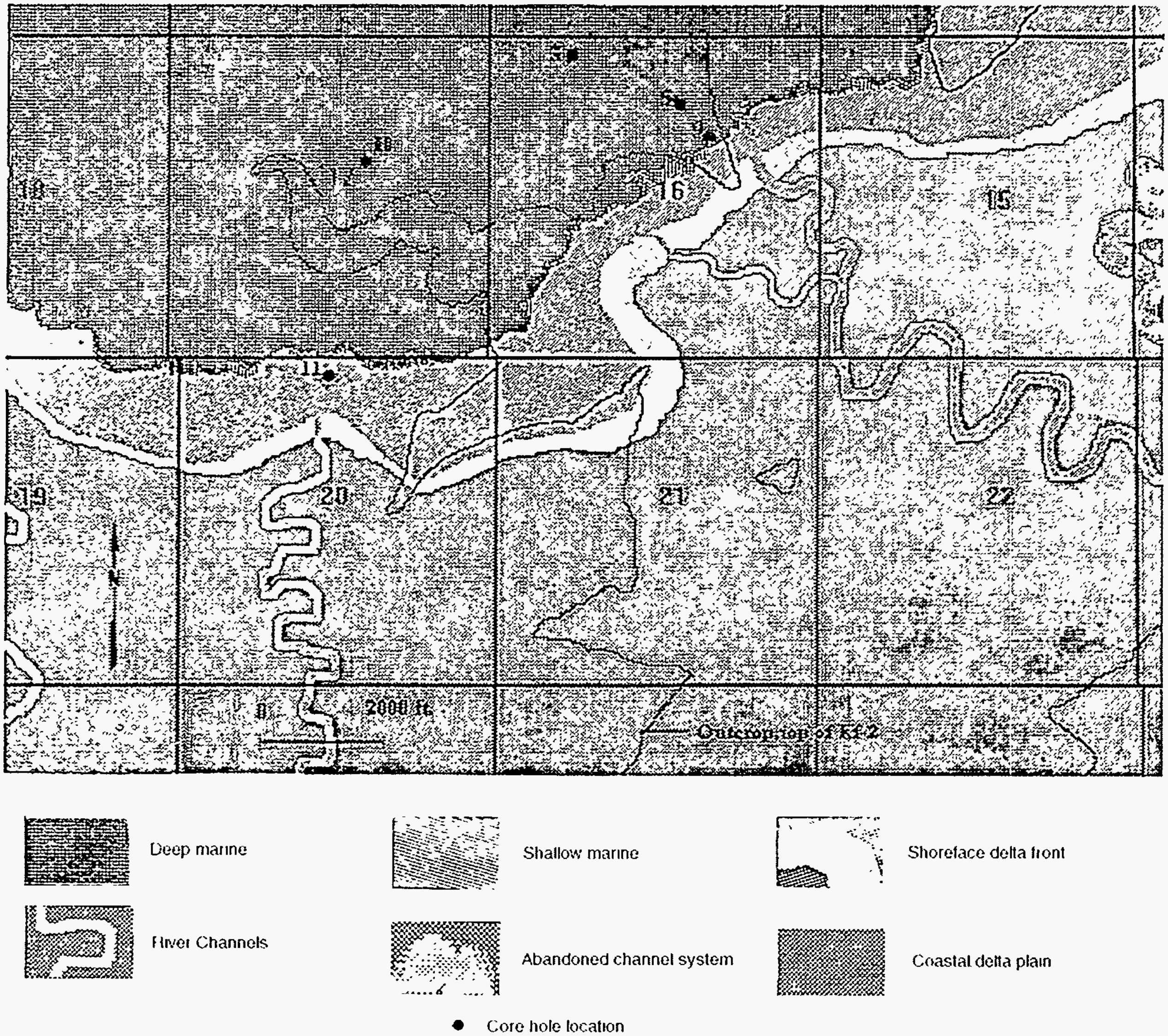
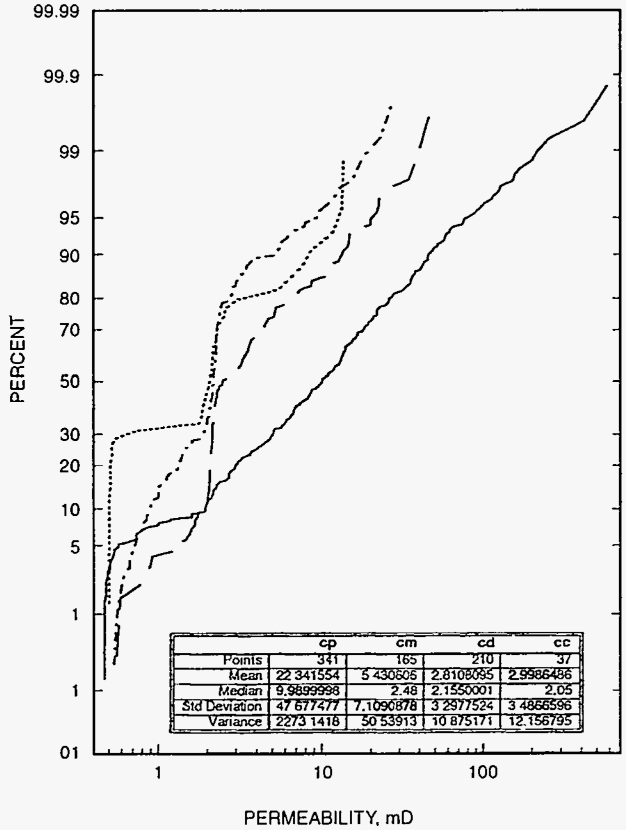


Fig. 3 Paleogeographic interpretation of the third of five time steps of the Kf-1–Ivie Creek-a parasequence. River channels flowing from the south and southeast deposited sands into a protected embayment in the northwest part of the area.



	cp	cm	cd	cc
Points	341	165	210	37
Mean	22 341554	5 430606	2.8108095	2.9986486
Median	9.9899998	2.48	2.1550001	2.05
Std Deviation	47 677477	7.1090878	3 2977524	3 4866596
Variance	2273 1418	50 53913	10 875171	12.156795

Fig. 4 Statistical analyses of Kf-1–Ivie Creek-a parasequence in the Ivie Creek case-study area showing cumulative percent of the four clinoform lithofacies vs. permeability. ——, cp. – –, cm. – · –, cd. · · · · ·, cc.

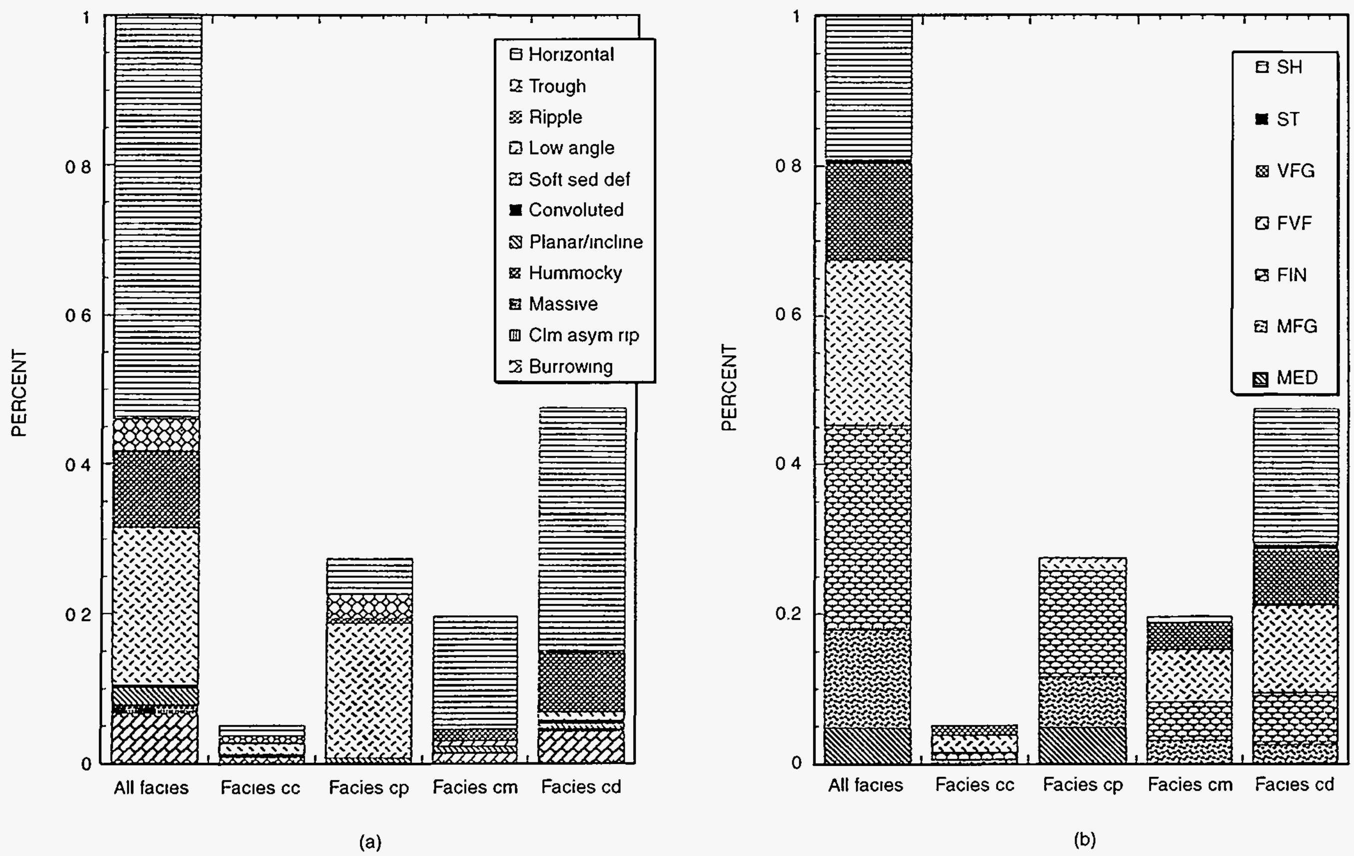


Fig. 5 Statistical analyses of the clinoform lithofacies from the Kf-1–Ivie Creek-a parasequence: (a) histogram showing relative frequency of sedimentary structure vs. lithofacies. (b) histogram showing grain-size distributions (megascopic observations) in each lithofacies (SH, shale; ST, silt; VFG, very fine grain; FVF, fine to very fine grain; FIN, fine grain; MFG, medium to fine grain; and MED, medium grain).

of Utah's Ferron Sandstone" was also presented to the Association of Petroleum and Mining Landmen on January 4, 1996, in Salt Lake City.

The UGS has established a home page on the Internet. The address is http://utstdpwww.state.ut.us/~ugs/. The site includes the Economic Geology Program page, which includes links describing the UGS/DOE cooperative studies (Ferron sandstone, Bluebell field, and Paradox basin) and a link to UGS's *Petroleum News*.

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