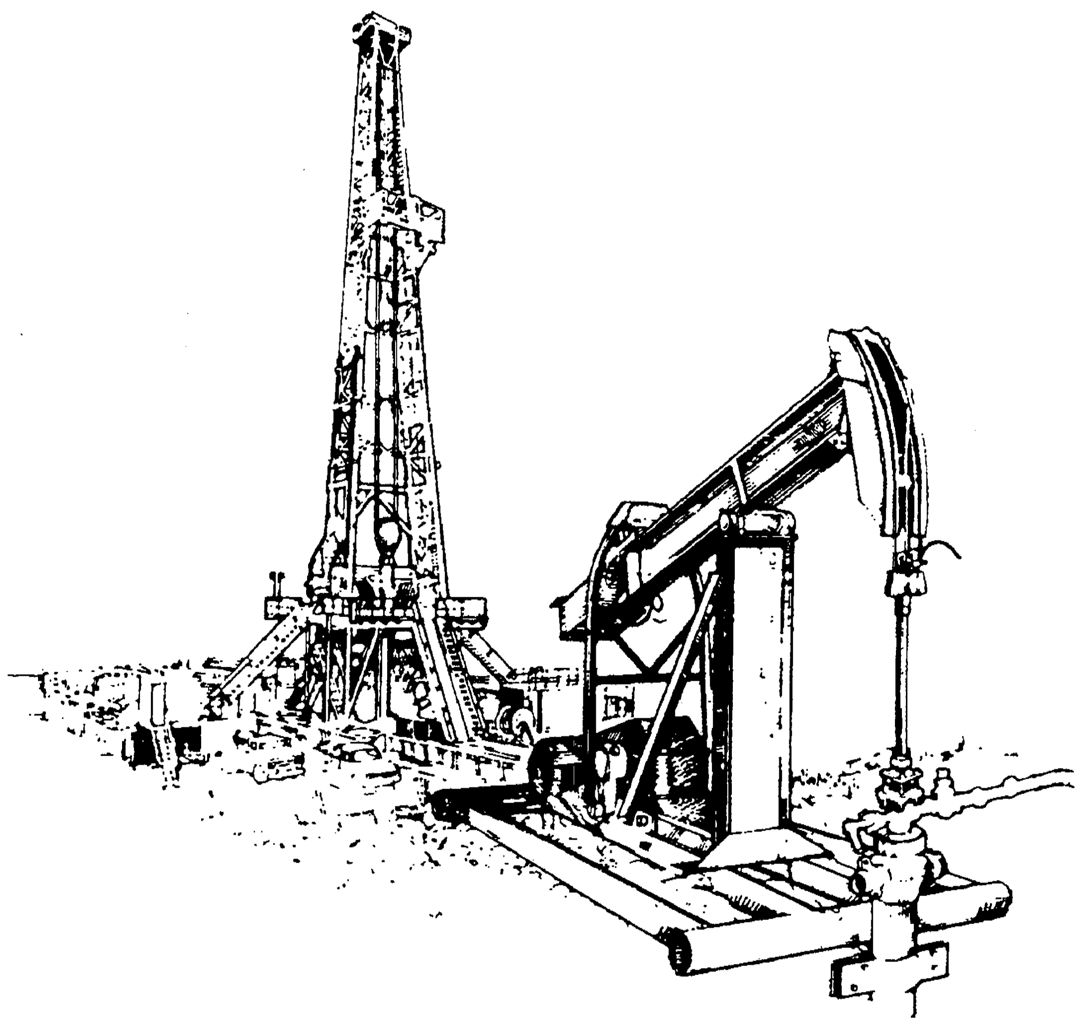
Contracts for field projects
and supporting research on . . .

89

Enhanced Oil Recovery

Reporting Period October–December 1996

DOE/BC--97/1
(DE98001288)
PROGRESS REVIEW
Quarter Ending December 31, 1996



United States Department of Energy
Office of Gas and Petroleum Technologies
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U.S. Department of Energy
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PATRICIA GODLEY
Assistant Secretary for Fossil Energy
Room 4G-084 Forrestal Building
Telephone Number 202-586-4695

SANDRA WAISLEY
Acting Director for Oil and Gas Exploration and Production

National Petroleum Technology Office
P.O. Box 3628
Tulsa, Oklahoma 74101
Telephone No. 918-699-2001

MICHAEL RAY
Acting Director

HERBERT A. TIEDEMANN
Technology Transfer Officer

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PROGRESS REVIEW NO. 89

CONTRACTS FOR FIELD PROJECTS AND SUPPORTING RESEARCH ON ENHANCED OIL RECOVERY

Date Published - April 1998

UNITED STATES DEPARTMENT OF ENERGY

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COMPANIES AND INSTITUTIONS

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Name	Phone number	Name of contractor
	U. S. Department of Energy Gas and Petroleum Technology Oil and Gas Exploration and Production 3E-028/FORS Washington, D.C. 20585	
	National Petroleum Technology Office P. O. Box 3628 Tulsa, Oklahoma 74101	
Jerry Casteel	918-337-4412	Amoco Production Company City of Long Beach Phillips Petroleum Company Strata Production Company University of Texas at Austin
Robert Lemmon	918-337-4405	University of Oklahoma
Rhonda Lindsey	918-337-4407	Fina Oil and Chemical Company Hughes Eastern Corporation University of Alabama University of Kansas
Chandra Nautiyal	918-337-4409	Laguna Petroleum Corporation Luff Exploration Company Michigan Technological University Oxy USA, Inc. Texas Exploration and Production, Inc. University of Kansas
Thomas Reid	918-337-4233	Stanford University University of Southern California

THERMAL RECOVERY—SUPPORTING RESEARCH

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 B. Reid
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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 work continued on the development of relative permeabilities during steam displacement. Two directions were pursued, one based on the use of a pore-network description of steam displacement[1] and another based on a double-drainage process. A model for double drainage that allows for the calculation of three-phase relative permeabilities as a function of the saturation of the respective phases, the history of the displacement, and the ratio in interfacial tensions was completed, and an M.S. thesis was written.[2] Work also continued on the analysis of the stability of phase-change fronts in porous media.

Investigation of the effect of gravity override during injection of a gas phase (such as steam) into porous media continued. A fundamental approach in which concepts from gradient percolation were used was developed with the use of pore-network models to describe the effect of gravity, capillarity, and viscous effects on the thickness of the gravity tongue. For stable displacement, the displacement front is compact and tilted at the angle given by the continuum theory, as expected. For unstable displacement, however, the thickness of the gravity tongue scales as a power law of the capillary number with exponents given from percolation theory. A crossover function was developed to capture the scaling behavior in terms of the capillary number and the gravity Bond number. This problem has implications for the prediction of gravity override.

The countercurrent flow of liquid and vapor in the presence of gravity is also being investigated. This process can be used for a variety of applications in heavy oil recovery. Researchers are interested in the displacement mechanisms that are studied by pore-network simulation and experiments.

Heterogeneity

Work continued on the optimization of recovery processes in heterogeneous reservoirs with the use of optimal control methods. During this quarter a technical paper on the subject was presented.[3] During the past quarter experiments continued in a Hele–Shaw cell with two controlled injection wells and one production well. Experiments are being conducted in homogeneous, as well as heterogeneous, cells with a particular form of heterogeneity to test the theoretical predictions. Current work involves further improvement of the numerical scheme for optimal control. The emphasis is on the effect of heterogeneity on optimal control predictions. In parallel, a variation of the control algorithm was used to solve a novel problem in porous media, namely, on how to design the injection rates in a three-well system in order for a parcel of fluid to follow a specific trajectory in the porous medium. This problem also occurs in the optimal placement of additives (for example, gels) in certain locations in the porous medium. Work in this direction started this quarter.

Refinement of the work to explain the origin of stabilized displacements in immiscible displacements in porous media from pore-network-level studies continued.[4] Work also continued on the identification of permeability heterogeneity. A technical paper was presented on a new technique to identify the permeability semi-variogram from multiple-well pressure transients.[5] In this technique, the theory of small fluctuations is used, which leads to a Volterra integral equation describing the ensemble-average behavior of the well pressure, from the inversion of which the permeability semi-variogram can be obtained. In addition, efforts to identify the entire permeability field from tracer profiles (e.g., those obtained from a computerized tomography scan) continued. An algorithm has been developed which is still being tested with synthetic data.

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 a hierarchy of minimum threshold paths in a disordered system. This theory was then applied to pore networks to determine the conditions for foam formation and mobilization. A technical paper summarizing the results was written.[6] This work shows how to compute parameters related to foam flow in porous media, such as the minimum pressure gradient for onset of foam flow and the fraction of trapped foam. The work is now extended to the problem of Bingham plastic flow in porous media.

References

1. C. Satik and Y. C. Yortsos, Pore-Network Studies of Steam Injection in Porous Media, submitted for publication in *Soc. Pet. Eng. J., SPEJ* (1996).
2. N. Halbhavi, M.S. Thesis, Three-phase Relative Permeabilities in Double Drainage, University of Southern California, December 1996.
3. B. Sudaryanto and Y. C. Yortsos, *Optimal Control of Displacement Fronts in Porous Media*, paper presented at the American Institute of Chemical Engineers Fall Meeting, Chicago, Ill., November 1996.
4. B. Xu, Y. C. Yortsos, and D. Salin, *Invasion Percolation with Viscous Forces*, paper presented at the American Institute of Chemical Engineers Fall Meeting, Chicago, Ill., November 1996.
5. Y. C. Yortsos and N. Al Afaleg, *Estimation of the Permeability Variogram from Pressure Transients of Multiple Wells in Heterogeneous Reservoirs: I. Theory and 1-D Application*, paper SPE 36510 presented at the Society of Petroleum Engineers Annual Fall Meeting, Denver, Colo., Oct. 6-9, 1996.
6. H. Kharabaf and Y. C. Yortsos, *A Pore-Network Model for Foam Formation and Propagation in Porous Media*, paper SPE 36663 presented at the Society of Petroleum Engineers Annual Fall Meeting, Denver, Colo., Oct. 6–9, 1996.

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: $460,000
(Current year)

Principal Investigator:
Khalid Aziz

Project Manager:
Thomas Reid
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 31, 1996

Objectives

The objectives of this 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) performing reservoir characterization studies to investigate reservoir heterogeneity descriptions relevant to applications of horizontal wells, and (3) experimental planning and interpretation to critically review technical literature on two-phase flow in pipes and correlate results in terms of their relevance to horizontal wells.

Summary of Technical Progress

During this quarter the following activities were carried out:

• Draft plans for the continuation of the two-phase flow experiments were drawn up and sent to Marathon and other members for their review and comments.

• Work on the application of horizontal wells for producing gas condensate reservoirs continued. After verification of the black oil formulation, emphasis is being placed on the compositional case where simulation runs have been set up to check the results against a semi-analytical solution.

• Work on the effects of heterogeneities on horizontal well performance continued.

• Research work on the development of coarse-grid methods to study cresting in horizontal wells continued. Correlations for optimum grid size, breakthrough time, and postbreakthrough behavior (i.e., water/oil ratio) were further tested and optimized. Procedures to derive pseudo-functions using either numerical correlations or coarse-grid simulations have been proposed and successfully tested. Accurate representation of cresting behavior requires fine-grid simulations that are costly and not always practical. Simple correlations for quick estimates of breakthrough time, maximum oil rate, and postbreakthrough behavior are derived on the basis of an appropriate set of dimensionless variables and an extensive number of simulation runs. The results and other calculations show that the correlations developed can be applied to a wide range of conditions for the prediction of the water breakthrough time and the water/oil ratio for horizontal wells. All the correlations are based on an assumption of two-phase, two-dimensional flow in homogeneous reservoirs.

Technology Transfer

The fourth review meeting of the Horizontal Well Industrial Affiliates Program was held on October 10–11 at Stanford. The meeting was well attended and well received. In addition to the project presentations, a number of member presentations were also made at the meeting. A paper done under this project was presented at the 1996 SPE International Conference on Horizontal Well Technology in Calgary in November.

GEOSCIENCE TECHNOLOGY—SUPPORTING RESEARCH

GYPSY FIELD PROJECT IN RESERVOIR CHARACTERIZATION

Contract No. DE-FG22-95BC14869

University of Oklahoma
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
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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

During this quarter the main activities involved modeling depositional environments. Research this quarter was focused on the modification of the developed multigrid simulator for pressure equation in reservoir simulation so that permeability can be considered as a tensor function of coordinates rather than the scalar function that is currently implemented.

The scalar approach has resulted in excellent convergence of the numerical algorithm for all practically important (but limited by the assumption of scalar form of permeability function) reservoir situations. Unfortunately, this is not the case for the tensor form of permeability function. The reason is in the form of projecting operation of the stiffness matrix from fine grid to coarse. Application of the projection operation results in losing information about tensor properties of permeability matrix on coarse grids. In other words, on coarse grid for each cell the components of the permeability tensor are being averaged automatically, which gives rise to the scalar form of permeability on the subsequent grids. The consequence is loss of convergence for certain geological structures or unrealistic change in pressure field.

Two ways of overcoming this problem can be suggested. The first approach is to choose another form of interpolation and residual transfer operators to maintain, not the continuity of the pressure distribution between neighboring cells (as it is implemented in the current version of the code), but rather to maintain continuity of fluxes and thus take into account characteristic features of permeability tensor on coarse grids. The second way is to form a stiffness matrix for each grid independently by using a renormalization procedure for permeability tensor. The disadvantage of this approach is that it is a high resource-consuming procedure.

FIELD DEMONSTRATION IN HIGH-PRIORITY RESERVOIR CLASSES

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
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 31, 1996

Objective

The objective of this work is to demonstrate the use of indigenous microbes as a method of profile control in waterfloods. As the microbial population is induced to increase, the expanded biomass is expected to 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 the 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. Special core analyses will be performed in order to arrive at the optimum nutrient formulation. (All tasks related to Phase I are complete except the analysis of baseline data.) 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

Analysis of Baseline Data

The analysis of baseline data is continuing.

Phase II: Implementation

Design of Field Demonstration

Completed.

Drill Three Additional Wells

Three new wells were drilled into the producing sand to try and determine the extent of nutrient-induced microbial growth through analysis of recovered core samples and produced fluids. The first well drilled was the NBCU 2-5 No. 2, which was spudded on Oct. 11, 1996, and reached a total depth of 2300 ft on October 17. The well encountered 24 ft of net Carter sand oil pay between 2192 and 2218 ft, and 43 ft of core was recovered. Visual observation of the core indicated that much oil remains in the low-permeability rock. The well was cased for production and fracture stimulated and as of the end of this quarter was awaiting installation of rod pumping equipment.

The second well drilled was the NBCU 2-13 No. 2, which was spudded on Oct. 22, 1996, and reached a total depth of 2305 ft on October 30. The well encountered 21 ft of net Carter sand oil pay between 2180 and 2205 ft, and 32 ft of core was recovered. Visual observation of the core indicated that much oil remains, as was observed in the previous well. The well was cased for production, perforated, and a packer and tubing were run. The well was swab tested at a rate of 480 bbl of fluid per day with 15 to 25% oil. The well was not fracture stimulated. As of the end of this quarter, rod pumping equipment had been installed and the well was shut in awaiting installation of electric power.

The third well drilled was the NBCU 2-11 No. 3, which was spudded on Nov. 6, 1996, and reached a total depth of 2306 ft on November 13. The well encountered 36 ft of Carter sand between 2164 and 2200 ft. A 32-ft core was recovered, which revealed significant remaining oil saturation, along with some portions that had obviously been swept by the waterflood. The water-swept sections should provide the best opportunity to observe microbial growth as a result of nutrient injection into the NBCU 2-6 No. 1 about 500 ft north of this well. The well was cased for production, was perforated, a packer and tubing were run, and the well was fracture stimulated. As of the end of this quarter, a flow line to the central production facility had been installed and flow testing had begun.

Sixteen 1-ft samples of core were obtained from each of the three wells. Ten of these cores were immediately placed in anaerobic containers and are being stored under anaerobic conditions. The remaining cores are being stored in closed containers with an air atmosphere.

Reservoir Characterization

Petrophysical studies of recovered core sample from the three newly drilled wells are in progress.

Analysis of Results

Monthly collection of produced fluids from the test and control wells in all patterns continued. Produced fluids are separated, and the following experiments are conducted on the separated samples:

- Aliphatic profile (gas chromatographic analysis).
- API gravity and absolute viscosity under reservoir temperature.
- pH of produced water.
- Surface tension of produced water (water–air).
- Interfacial tension for produced oil–water system.
- Microbiological population.
- Inorganic analyses (nitrate, phosphate, sulfate, sulfide, chloride, potassium, and hardness).

Production data on all wells in all patterns continue to be plotted and evaluated. It is still premature to draw definite conclusions about the performance of the microbial enhanced oil recovery (MEOR) treatment, but preliminary evaluation of the production data and water/oil ratio data shows the following trends. Of the 15 wells that are in test patterns, the oil production in 8 of the wells is either holding or increasing, which indicates a positive response to the MEOR injection program. Of the 8 wells that are only in control patterns, oil production shows a natural decline in 5.

BASIN ANALYSIS OF THE MISSISSIPPI INTERIOR SALT BASIN AND PETROLEUM SYSTEM MODELING OF THE JURASSIC SMACKOVER FORMATION, EASTERN GULF COASTAL PLAIN

Contract No. DE-FG22-96BC14946

University of Alabama
Tuscaloosa, Ala.

Contract Date: Aug. 29, 1996
Anticipated Completion: Aug. 22, 2001
Government Award: $80,000
(Current year)

Principal Investigator:
Ernest A. Mancini

Project Manager:
Rhonda Lindsey
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 31, 1996

Objectives

The objectives of this project are to provide improved access to information available in the public domain by inventorying data files and records of the major information repositories in the Eastern Gulf Coastal Plain and making this inventory easily accessible in electronic format. The producers in the region maintain that the accessibility of oil and gas information is the single-most important factor to assist them in finding new hydrocarbon discoveries and in improving production from established fields.

Summary of Technical Progress

Discussions of the project continue with the state geologists for Alabama and Mississippi. Subcontracts are being drafted to initiate the anticipated work effort between the University of Alabama and the Geological Survey of Alabama and Mississippi Office of Geology.

The project was discussed with a number of faculty members from departments of geology in the region. A letter was sent to 12 department chairs in Alabama, Florida, Louisiana, and Mississippi to facilitate the acquisition of theses and dissertations related to the petroleum geology of the Mississippi Interior Salt Basin. A listing of theses and dissertations has been received from the University of Alabama, Mississippi State University, University of Southern Mississippi, and Louisiana State University.

The project was discussed with additional representatives from several service companies that provide land-grid, geological, and geophysical data related to the wells and fields located in the Mississippi Interior Salt Basin area.

The project was discussed with the State Geologist for Florida and geologists with independent and major companies.

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

Project Managers:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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 reservoirs for the project are the Camerina sands located on the west and north flanks 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

West Flank Performance

The current injection strategy is to split the 4.0 million standard cubic feet per day (MMSCFD) of available air injection capacity between the west flank and the north flank of the field. On the west flank, air has been injected into two fault blocks, fault blocks II and IV. Out of more than 1.5 billion standard cubic feet (BSCF) of air injected to date, more than 1.2 BSCF of air has been injected into fault block IV. Figure 1 shows cumulative air injected vs. time. The most upstructure producer in fault block IV still produces a 98 to 99% water cut, and no evidence of nitrogen breakthrough has been seen. Production response is expected in fault block IV after sufficient air has been injected to push the oil rim down to the most upstructure producing well, the Gulf Land D No. 44.

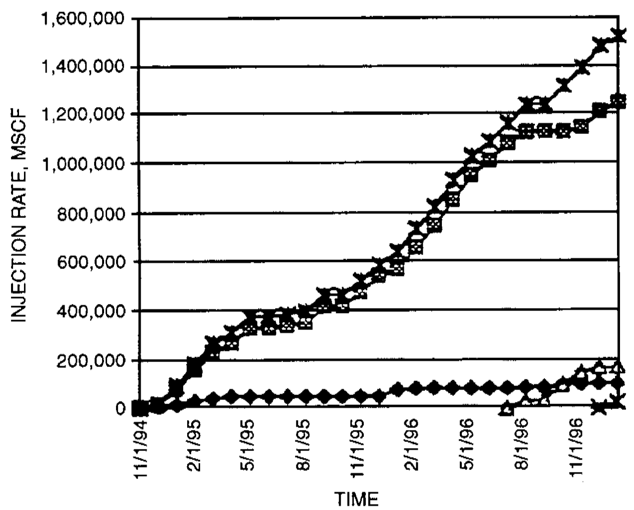


Fig. 1 Plot of cumulative air injected vs. time, West Hackberry Tertiary Project. —◆—, Watkins 16 and 18 wells (west flank, fault block II). —■—, Gulf Land D No. 51 well (west flank, fault block IV). —△—, SL 155 (north flank, Cam C). —×—, Gulf Land AC 245 well (north flank, Bol 3). —✱—, total accumulation.

The injector for fault block IV is the Gulf Land D No. 51. In July 1996, Gulf Land D No. 51 plugged up with sand fill. In October, a repair was completed that included cleaning out the wellbore and gravel packing the completion interval. The repair was successful, and injection in the Gulf Land D No. 51 has been trouble-free since the repair. Figure 2 shows injection rates and pressures for the Gulf Land D No. 51. Although the oil rim has not yet reached the producer in fault block IV, reservoir pressure has increased by 350 psi since the start of injection. Figure 3 shows the bottom-hole pressure vs. time.

Within the first 6 months of project startup, fault block II exhibited early nitrogen breakthrough with no increase in oil production. As a result, the injection strategy was modified to inject in fault block II only when the air injectors in the other fault blocks are incapable of taking the project's full 4.0-MMSCFD capacity.

North Flank Performance

Air injection was initiated on the north flank of West Hackberry in the Cam C sand in July 1996. The target reservoir possesses a thin oil rim bordering a large low-pressure gas cap. Reservoir pressure in the project area falls between 350 and 550 psi. The air injector for the north flank Cam C is the SL 42 No. 155. Figure 4 shows the north flank air injection rates and pressures. On the north flank of the field, oil production averaged 180 to 210 bbl of oil per day (BOPD) in the months preceding initial air injection. After north flank air injection began in July 1996, oil production steadily increased in three nearby producing wells to 370 BOPD as of October 1996. In addition, water cut declined from 50 to 35%. Figure 5 shows the injection and

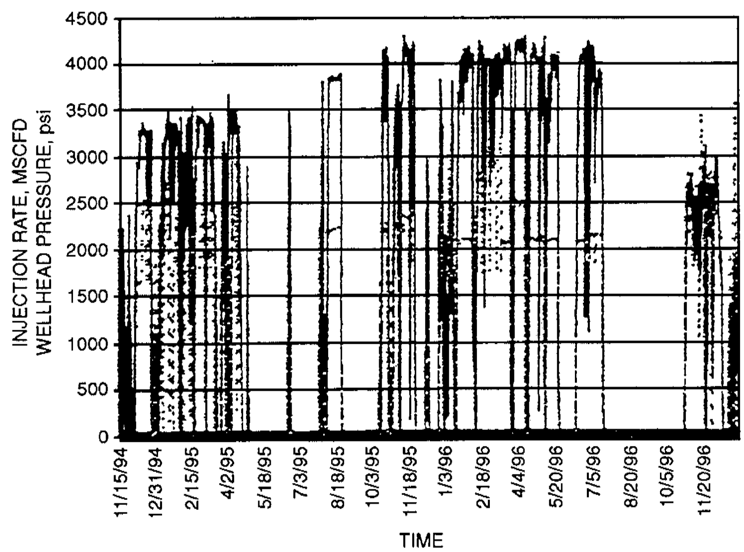


Fig. 2 Plot of air injection rates (——) and wellhead pressures (- - - -) for Gulf Land D No. 51 well (fault block IV, west flank).

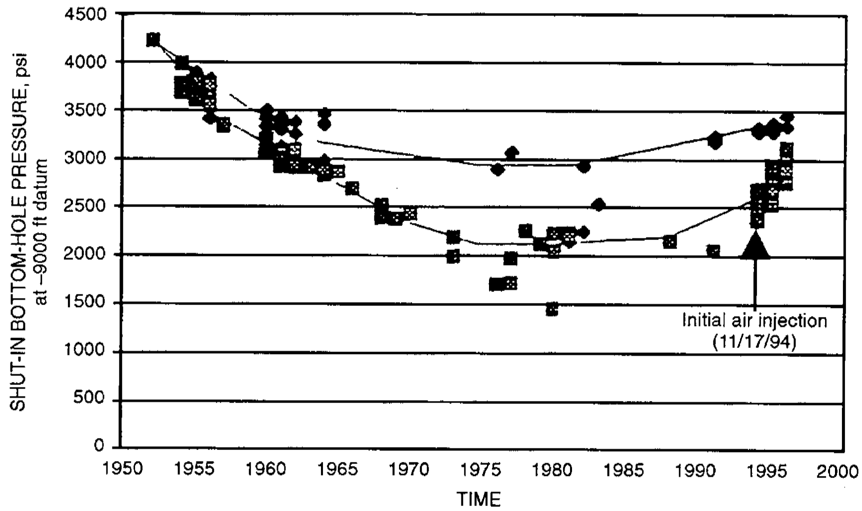


Fig. 3 Plot of bottom-hole pressure vs. time (west flank), West Hackberry air injection project. —◆—, fault blocks I and II. —■—, fault blocks III, IV, and V.

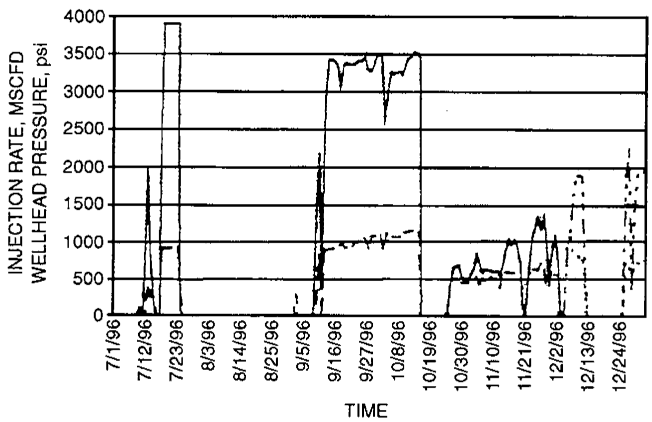


Fig. 4 Plot of air injection and wellhead pressure, north flank injectors [SL 42 No. 155 (Cam C) and Gulf Land D AC No. 245 (Bol 3)] (155 was shut in when 245 began injection on 12/4/96). — - - —, Gulf Land D AC No. 245 injection rate. · · · ·, Gulf Land D AC No. 245 wellhead pressure. ——, SL 155 injection rate. – – –, SL 155 wellhead pressure.

production rates vs. time for the north flank Cam C. As noted on the injection plot, on Dec. 4, 1996, air injection was stopped in the Cam C to begin injection in the Bol 3 sand. Corresponding to the reduction in air injection rates in the Cam C, oil production has also decreased. Air injection will resume in the Cam C during January 1997 in an effort to return production to the October 1996 levels.

The injection of air into the low-pressure Cam C is increasing oil recovery by (1) pushing the oil rim downstructure to the structural location of existing wellbores, (2) repressurizing the reservoir, and (3) obtaining tertiary oil recovery through DDP. Although nitrogen, carbon dioxide, and natural gas have been used to increase oil recovery in Gulf Coast reservoirs in the past, this project is unique in the use of air as the injection gas.

Several of the wells surrounding the air injector, the SL 42 No. 155, have had an increase in nitrogen and a minor amount

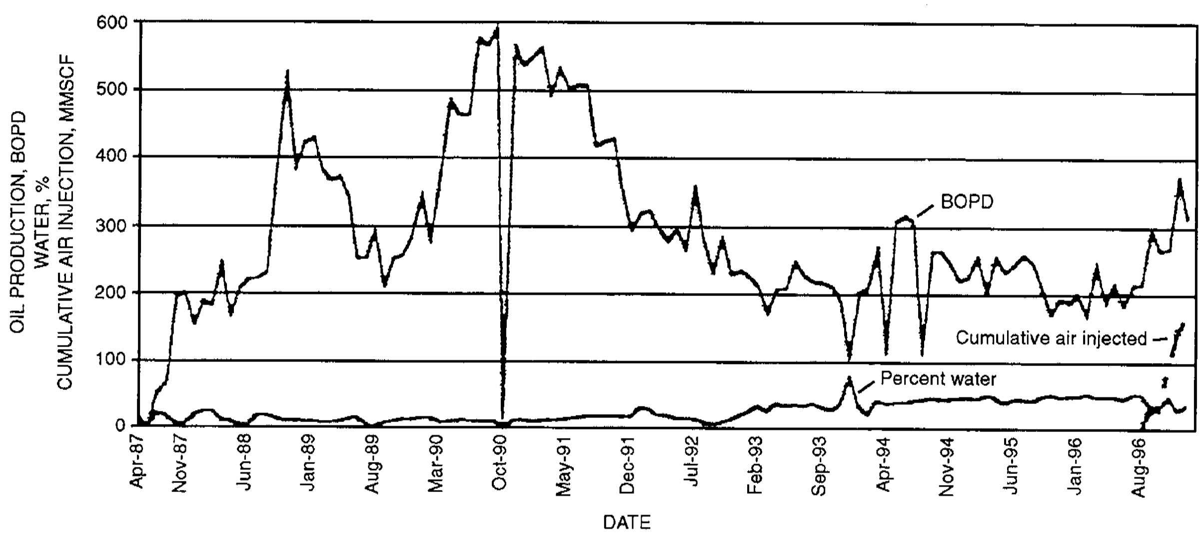


Fig. 5 North flank Cam C producers, West Hackberry air injection project.

of oxygen in the produced gas. As expected, the increased nitrogen and oxygen content moderated after the air injection rate in the SL 42 No. 155 was reduced. The oil production rate also declined during November and December as a result of reduced air injection.

As noted earlier, air injection began in a low-pressure Bol 3 sand on the north flank on Dec. 4, 1996. The Gulf Land A R/A C No. 245 is the upstructure well that serves as the injector for the Bol 3. The Gulf Land D No. 46 is the downstructure producer for the Bol 3. The volume of air injected during December 1996 has not been sufficient to increase oil production in the Gulf Land D No. 46. The need to inject a sufficient volume of air to generate production response in the Bol 3 must be balanced with the effort to maximize oil production in the Cam C.

Air compression consists of an Atlas–Copco ZR-6 two-stage oilless screw compressor in series with an Ariel JGK-4 five-stage reciprocating compressor. Air is compressed from atmospheric pressure to 4000 psi. Both compressors are driven by Waukesha GL series lean-burn natural gas engines.

The only major cause of unscheduled downtime (9 d) during the quarter was a problem with the Waukesha 5108 GL engine on the screw compressor. A leaking packing ring on a cylinder sleeve was allowing the cylinder coolant and the crankcase oil to mix, which caused the oil to become contaminated with water. The cylinder sleeve had no damage or abnormal wear and was installed with new packing rings and a new piston. The old piston showed signs of possible detonation and was sent to Waukesha for inspection and analysis. The fuel gas is also being analyzed to determine if the quality and octane rating have changed. A cracked water-cooled exhaust manifold was allowing coolant to be lost through the exhaust, and therefore a new exhaust manifold was installed. Two additional days of downtime were incurred for scheduled preventive maintenance.

Technology Transfer

A short talk on air injection that included a discussion of the West Hackberry project was presented at the Society of Petroleum Engineers (SPE) Annual Technical Conference and Exhibition in Denver, Colo., in October 1996. After obtaining Department of Energy approval, news releases documenting the project's increase in oil production were sent to the SPE's *Journal of Petroleum Technology* and the *American Oil and Gas Reporter.*

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
(Current year)

Principal Investigators:
Mark A. Sippel
Larry A. Carrell

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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.

Improved reservoir characterization with the use of three-dimensional (3-D) and multicomponent seismic is being investigated for identification of structural and stratigraphic reservoir compartments. These seismic characterization tools are integrated with geological and engineering studies. Improved completion efficiency is being tested with short-lateral and horizontal drilling technologies. Improved completion efficiency, additional wells at closer spacing, and better estimates of oil in place will result in additional oil production by primary and enhanced recovery processes.

Summary of Technical Progress

Ratcliffe Reentry Lateral Completions

Two wells in the North Sioux Pass field (2-16 State and M-17 Trudell) were selected for reentry lateral completion in the Ratcliffe (Fig. 1). The laterals were to be drilled out from 14-cm (5½-in.) casing with steered-motor technology and planned extensions of 610 m (2000 ft). The planned orientation of the laterals was to be normal to the fracture orientation observed from the 1-17R Federal core and formation microimaging (FMI) log data (Fig. 2).

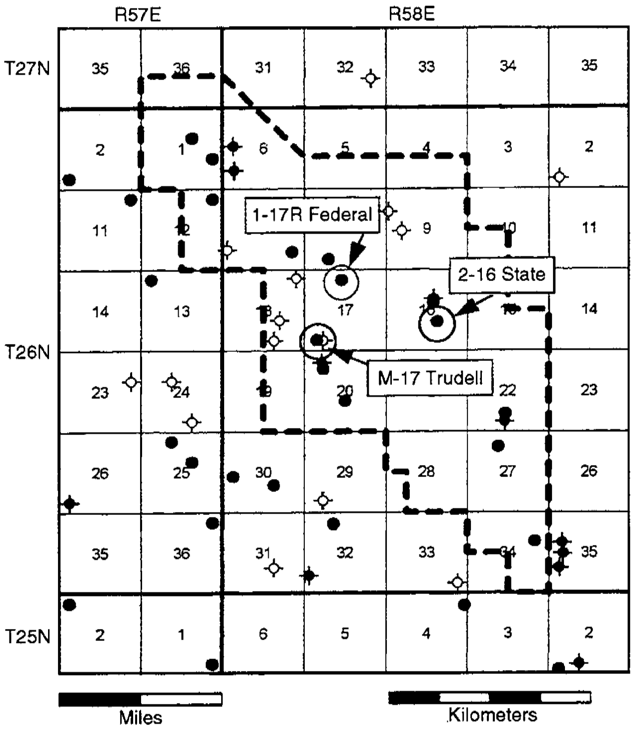


Fig. 1 Map of 3-D seismic survey locations for North Sioux Pass field, Richland County, Mont.

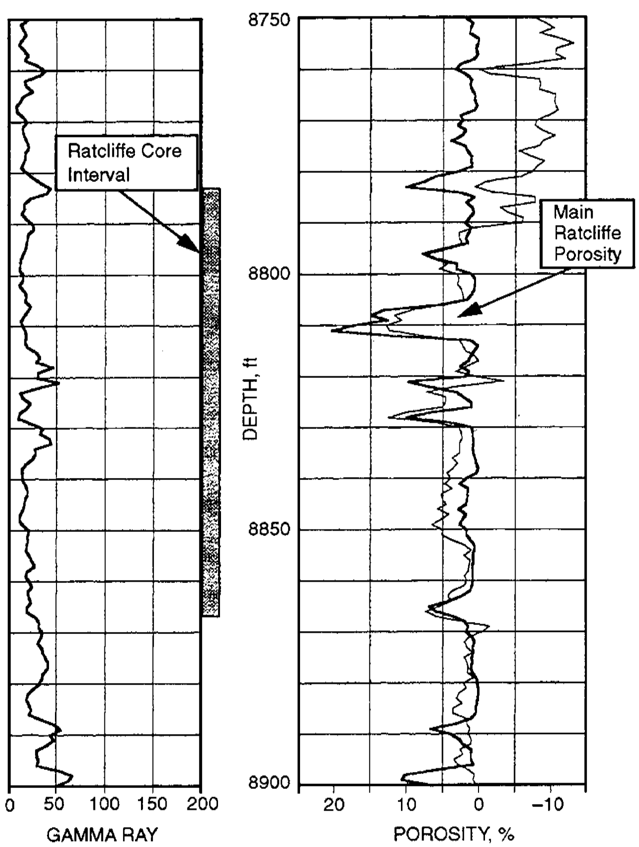


Fig. 2 Porosity log across the Ratcliffe interval from the No. 1-17R Federal, North Sioux Pass field, Richland County, Mont.

With slim-tool technology, a lateral drain hole with a horizontal length of 604 m (1982 ft) was drilled in the 2.1-m (7-ft) porosity zone of the Ratcliffe (Fig. 2). The lateral was drilled successfully after two attempts. On the first attempt, a casing window was cut from 2705 to 2707 m (8875 to 8881 ft) and a whipstock was emplaced. Operations commenced on Nov. 14, 1996, with directional control and measurement while drilling (MWD) provided by Baker Hughes Inteq. It was determined that the directional tools were not building sufficient angle and correct azimuth after drilling only 17 m (57 ft). The well was plugged back with cement to 2708 m (8884 ft). The second attempt was successfully drilled in 15 d. The Ratcliffe porosity bench remained relatively flat throughout the course of the lateral with a downward dip rate of about 1%. Sample shows were good throughout the lateral. The well has not pumped long enough for withdrawal of all load water and to evaluate a stabilized oil cut. It is currently producing at 2.1 m^3 of oil and 20.0 m^3 of water per day [13 bbl of oil per day (BOPD) and 126 bbl of water per day (BWPD)].

Slim-tool technology was used to attempt the drilling of a short-radius drain hole in the Ratcliffe through a casing window. A casing window was cut from 2633 to 2635 m (8639 to 8646 ft) and a whipstock was emplaced. Operations commenced on Dec. 17, 1996. Kickoff was at a depth of 2636 m (8648 ft) with directional control and MWD provided by Baker Hughes Inteq. After drilling only 13 m (44 ft) to 2649 m (8692 ft), it was determined that the directional tools were not building sufficient angle or correct azimuth. Operations were suspended on December 27.

Red River Targeted Drilling

Drilling operations were completed at the B-27 State-Muslow well in Bowman County, N. Dak. (Fig. 3). The vertical well was targeted from a three-dimensional (3-D) seismic survey over Cold Turkey Creek field. Results from the well are encouraging. Commercial porosity was developed in the Red River B and D zones.

Contiguous cores were cut across the entire upper Red River section from 2847 to 2905 m (9340 to 9530 ft). These cores covered all four porosity benches (A, B, C, and D zones) in the Red River (Fig. 4). Sonic and density logs were obtained for further synthetic-seismogram study and evaluation of the 3-D seismic survey.

Drill-stem tests (DSTs) were run in the Red River B, C, and D zones. The B zone test indicated normal permeability for the interval with drawdown pressure at 12,700 kPa (1842 psig). Original reservoir pressure was 26,890 kPa (3900 psig). The C zone DST was indicated to have low permeability with only 15 m (50 ft) of mud recovered. The shutin pressure was 22,194 kPa (3219 psig). The D zone recovered 506 m (1660 ft) of fluid and had a shutin pressure of 26,841 kPa (3893 psig).

Evaluation of electrical log and core data indicates 2.1 m (7 ft) of pay in the Red River B zone with 16.3% porosity and

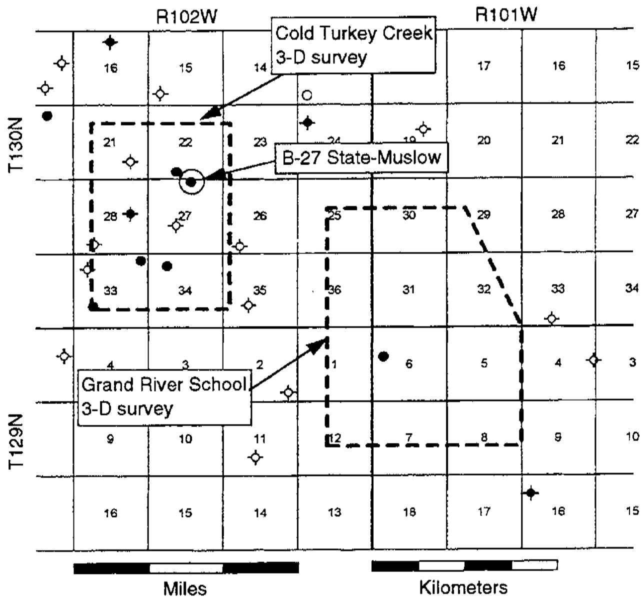


Fig. 3 Map of 3-D seismic survey locations for Cold Turkey Creek and Grand River School fields, Bowman County, N. Dak.

21.0% water saturation. The C zone indicates 3.0 m (10 ft) of porosity, which averages 8.7%, and 47.2% water saturation. A productive thickness of 7.6 m (25 ft) with 11.4% porosity and 47.4% water saturation is calculated for the D zone.

The D zone was perforated from 2903 to 2912 m (9524 to 9554 ft) and acidized. The completed interval is producing 22 m^3 of oil and 13 m^3 of water per day (140 BOPD and 80 BWPD) with a fluid level of 1219 m (4000 ft) from surface. The B zone is also productive and remains behind pipe. Plans for completing the B zone will be made after the D zone is fully evaluated and analysis of feasibility for secondary recovery by waterflooding in the B zone is complete.

Red River Lateral Drilling

Luff Exploration Company participated in the drilling of a horizontal completion in the Red River B zone reservoir at State Line field, Bowman County, N. Dak. (Fig. 5). The objective of the well was to exploit additional primary reserves by overcoming poor drainage caused by heterogeneity. The No. 1-26H Greni well is the fourth well on a small Red River feature that has produced more than 143,090 m^3 (900,000 bbl) of oil from B and D zones of the Red River since 1973.

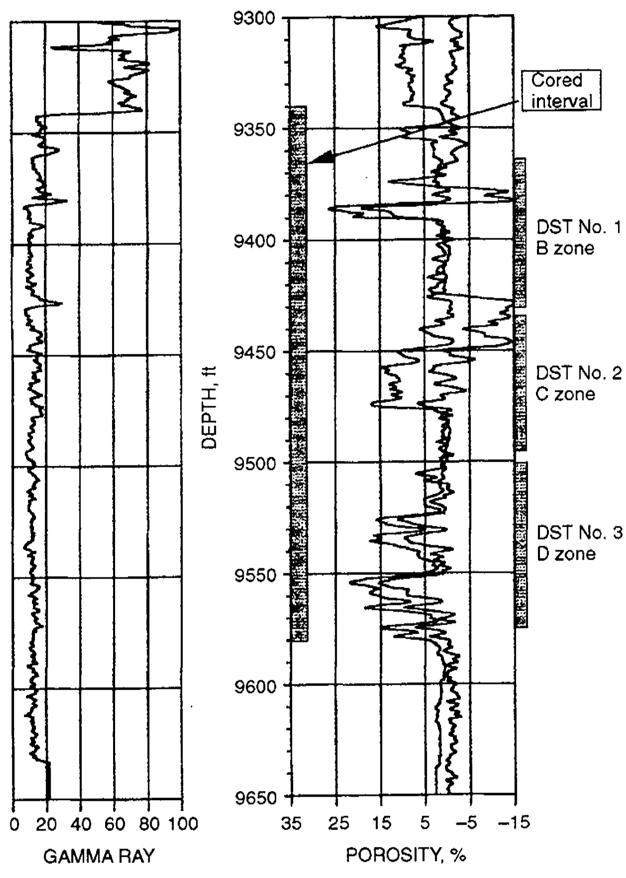


Fig. 4 Porosity log from the B-27 State-Muslow well in Cold Turkey Creek field, Bowman County, N. Dak.

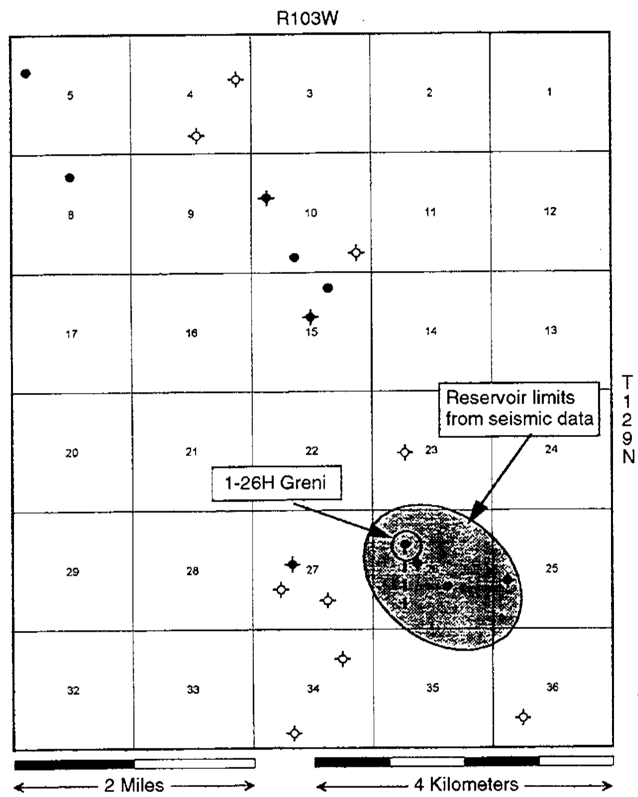


Fig. 5 Map of State Line field, Bowman County, N. Dak. The No. 1-26H Greni was drilled as a new horizontal well for the Red River B zone.

The well was drilled on the west side of the structure and encountered the Red River B at a subsea datum that was 20 m (67 ft) low to the most updip well. A lateral reach of 846 m (2775 ft) was drilled in the Red River B. With the use of an invert mud system, the vertical portion of the hole was drilled with a 22.2-cm (8¾-in.) bit. The lateral portion of the hole was drilled in less than 4 d with a 15.6-cm (6⅛-in.) bit. With the use of a freshwater mud system, an MWD gamma ray was run throughout both the build and lateral sections.

The well has been producing from the open-hole lateral section in the Red River B zone since October 1996. Production has been disappointing at 2 m^3 of oil and 52 m^3 of water per day (10 BOPD and 330 BWPD). The drilling of No. 1-26H Greni appears to have been a mechanical success but a failure with regard to reservoir development. The relatively low structural position to offset production and poor oil cut indicate completion of the lateral below an oil–water contact. Results from this well indicate that commercial oil saturation in the Red River B zone is not ubiquitous and that understanding trapping (either structural or stratigraphic) is important in this immediate area for placing horizontal wells in the Red River B horizontal play.

The M-20H Stearns was spudded on Nov. 15, 1996. The well was drilled with the goal of evaluating water injection through a horizontal open-hole completion in the Red River B zone. Drilling operations were suspended after 50 d when efforts to retrieve stuck drill pipe in the lateral section were unsuccessful.

Drilling plans called for a vertical pilot hole with a DST of Red River B porosity to establish structural, pressure, and fluid relationships with nearby producing wells before plugging back to the Interlake to kick off the build section. A lateral reach of 1219 m (4000 ft) was planned that was to traverse between two producing wells in the Red River B zone (Fig. 6).

Total depth of the 22.2-cm (8¾-in.) vertical hole was reached at 2755 m (9040 ft) in the Red River after 22 d of drilling. Electrical logs were run, and a DST was run across the Red River B zone. The hole was then plugged back to the Interlake at 2467 m (8094 ft). The plug was dressed to 2536 m (8321 ft) before drilling operations for the build section began. Drilling of the build section required 8 d, and 17.8-cm (7-in.) casing was set at 2751 m (9025 ft), 2664 m true vertical depth (8741 ft). The lateral section was drilled with a 15.6-cm (6⅛-in.) bit, and fresh water was used for drilling fluid. After 11 hr of drilling the lateral section, the drill pipe became stuck. The lateral reach from the 17.8-cm (7-in.) casing was 309 m (1015 ft). Fishing efforts were unsuccessful.

The DST in the Red River B zone indicated oil and depleted reservoir pressure of 7529 kPa (1092 psig). Reservoir pressure of 7584 kPa (1100 psig) was determined by fluid buildup at an offset well in June 1996. Electrical logs indicate 3.0 m (10 ft) of net pay in the Red River B zone with maximum porosity of 27%. These data confirm previous data analysis and characterization of the B zone reservoir. The reservoir assumptions for the planned water-injection test are valid.

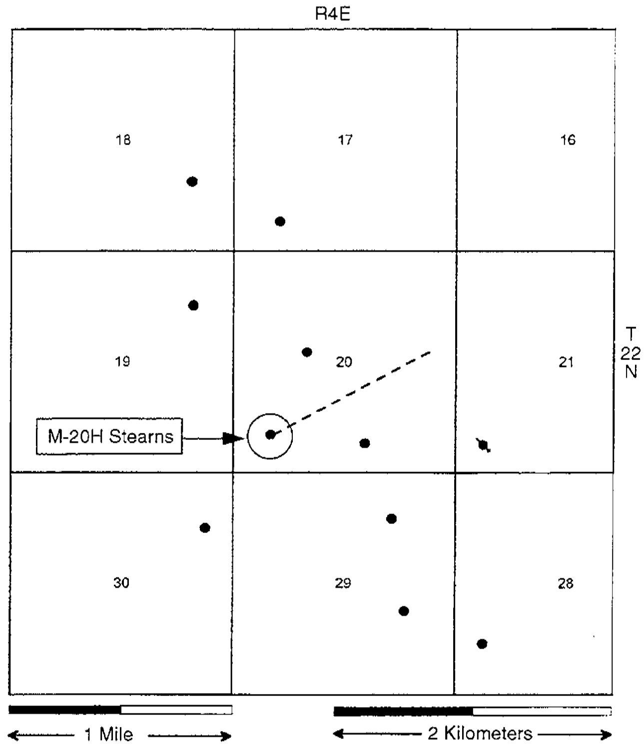


Fig. 6 Map of Buffalo field (north area), Harding County, S. Dak. M-20H Stearns well was to test water injection through a horizontal completion in the Red River B zone.

Current plans are to put the well on pump with the drill pipe still in the hole. It is hoped that this will remove blockage and allow eventual removal of the stuck drill pipe. If fluid entry rate after 30 to 60 d is encouraging, plans are to initiate the water-injectivity test.

Ratcliffe Geophysical Survey

Interpretation of 3-D seismic data at North Sioux Pass, Richland County, Mont., is in progress for the Ratcliffe. The 3-D seismic survey covers approximately 38 km^2 (15 $miles^2$) in T. 26 N., R. 58 E. (Fig. 1).

Red River Geophysical Survey

Interpretation of 3-D seismic at Cold Turkey Creek and Grand River School continues. Attribute studies in the Red River have been augmented from sonic and density log data collected from the B-27 State-Muslow well at Cold Turkey Creek (Fig. 3).

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: $7,572,930

Principal investigator:
J. W. Nevans

Project Manager:
Rhonda Lindsey
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 31, 1996

Objective

The objective of this project is to demonstrate the application of advanced secondary recovery technologies to remedy producibility problems in a typical shallow-shelf carbonate 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

As part of the field demonstration phase of the project, 18 10-acre infill wells have been drilled and completed at the North Robertson (Clearfork) Unit (NRU). The 14 producing wells are pumped off and are producing at stable rates. The 4 injection wells are complete and have been on injection for 3 to 4 weeks. Current Unit production is approximately 3400 stock tank barrels of oil per day (STBO/d), of which approximately 900 STBO/d is being produced from the 10-acre infill wells (Fig. 1). A change in the Statement of Work has been approved so that additional 10-acre infill wells can be drilled and/or 20-acre producing wells can be converted to injection.

Field Demonstration

Implementation of Field Demonstration

Core analysis. As part of an intensive effort to collect needed rock data, 2730 ft of core was cut in four wells. The data will be used to help quantify the extent of small-scale vertical and lateral heterogeneity, refine the depositional model, improve understanding of the relationship between porosity and permeability, and help in the selection of additional 10-acre infill drilling locations within the NRU Clearfork formation.

The core was initially described by Fina geologists in Midland, Tex., and then sent to David K. Davies & Associates, Inc., in Kingwood, Tex., for a more-detailed description. Special core plugs (1.5 in. × 3 in.) were cut and then stored in sealed containers filled with degassed lease crude to preserve the native state of the rock characteristics and fluid content. The special core work is being performed by Core Petrophysics in Tulsa, Okla.

Field Operations and Surveillance

Well testing. One injection well in sec. 329 (No. 3536) was preproduced for a 3- to 4-week period before being placed on injection in order to conduct near-wellbore wettability tests and to try to optimize both injection and production in all wells. After the well was placed on production, wettability was altered from the natural oil-wetting tendency to water wet in the near-wellbore region to determine the effect on production efficiency. Making the rock water wet in the near-wellbore region meant that formation water was coating the rock surfaces and that the oil was in the center of the pore space.

Altering the near-wellbore wettability did not significantly alter the producing characteristics of the well, although this may have been because the well had significant paraffin- and asphaltine-formation tendencies, which are normal operating problems at the NRU. The well was placed on injection, and the wettability in the near-wellbore region was returned to its natural oil-wet condition. It is hoped that from these experiments the optimum wetting conditions for both production and injection can be determined.

Interval testing was performed in the lower Clearfork zone on two wells (Nos. 1509 and 3534), in the middle Clearfork zone on two wells (Nos. 3532 and 2705), and in the upper Clearfork interval on one well (No. 3018) to determine the relative contribution of each completed interval to production. In addition to interval producing rates, pressure drawdown data were recorded as each well's producing fluid level was pumped down, and analyses were performed to provide information concerning the production efficiency of each zonal completion. The results of these tests are summarized in the Reservoir Management section of the report.

Reserves—incremental vs. accelerated. Early results indicate that approximately 65% of the production from the new infill wells is incremental and approximately 35% may

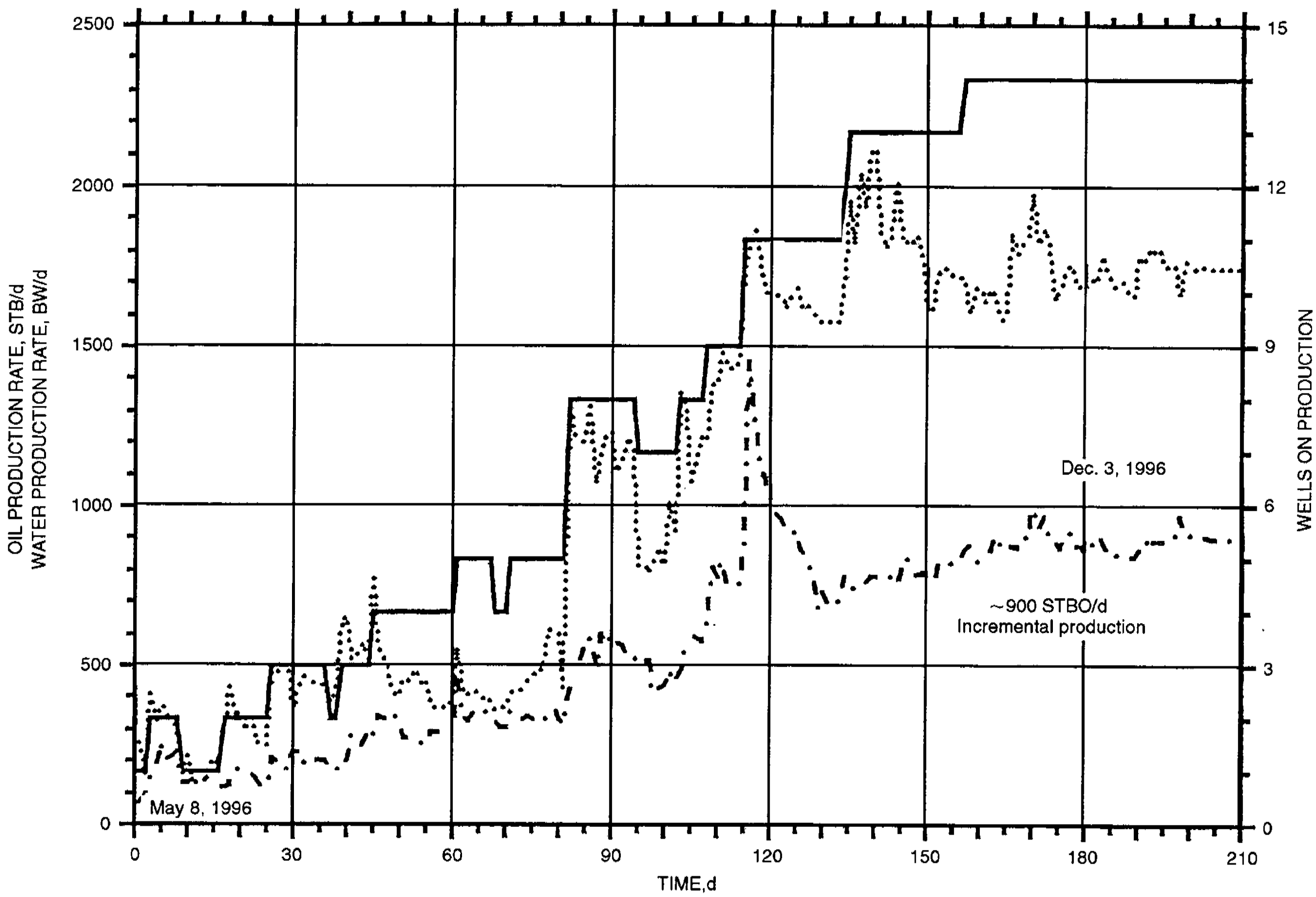


Fig. 1 Incremental production increase as the result of new 10-acre infill wells, North Robertson Unit. —·, incremental oil. ····, incremental water. ——, wells on production.

be acceleration of existing reserves. The new wells account for approximately 900 STBO/d of the total Unit production, and the amount of incremental production since the Field Demonstration was implemented is between 600 and 700 STBO/d. On an individual well basis, most of the additional production in sec. 329 of the Unit (Fig. 2) appears to be the result of acceleration of existing reserves, whereas most of the additional production in secs. 326 and 327 appears to be incremental. These trends were predicted before drilling on the basis of differing reservoir rock types that occur in the two areas. The sec. 329 infill area is dominated by grainstone shoal facies with fairly good permeability and porosity. The reservoir within secs. 326 and 327 is dominated by lagoonal facies with good storage capacity (porosity) but relatively lower permeability and connectivity. Individual well producing characteristics will be monitored in an effort to quantify incremental reserves added via infill drilling.

Well stimulation. With the use of data (cores and logs) acquired during the Field Demonstration phase of the project, discrete intervals within the Glorieta/Clearfork section that contribute most to production can be identified. These are intervals of relatively high permeability and porosity which are separated by larger intervals of lower permeability and porosity rock that act as source beds for the higher quality reservoir rock. These intervals include:

Lower Clearfork:	MF4 and MF5 zones (±7000 to 7200 ft)
Middle Clearfork:	MF1A, MF2, and MF3 zones (±6350 to 6500 ft and ±6750 to 6900 ft)
Upper Clearfork:	CF4 zone (varies in Unit) (±6150 to 6200 ft)

Three-stage completion designs were used to keep the treated intervals between 100 and 250 ft. Both CO_2 foam fracs and conventional cross-linked borate fracs were done. All well rates have held up extremely well over time for both hydraulic fracture designs. The major factor controlling initial potential appears to be confinement of the vertical completion interval and localized reservoir quality.

Integration/Validation

Validation of Reservoir Characterization

Depositional environments. Additional refinements were made to the depositional environment model on the basis of data from recently acquired core taken from the latest 10-acre infill wells. The planned coring program and a cursory

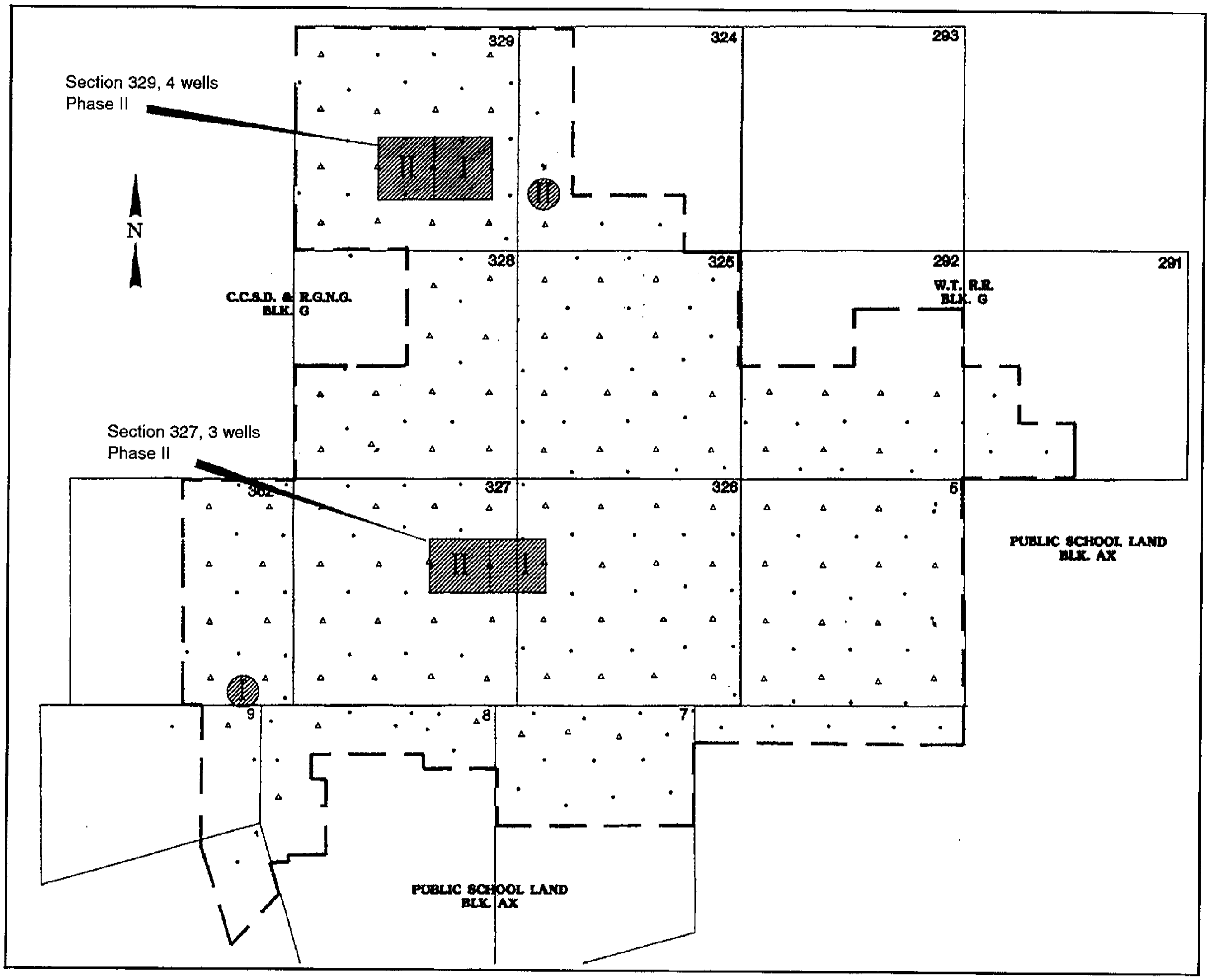


Fig. 2 Potential development areas for phase I (11 wells) and phase II (7 wells) drilling.

description of these cores are complete. This represents 2730 ft of core in four wells. The preliminary depositional environments described from the new data are:

- Open Shelf
  - Open Shelf— general
  - Fusilinid Shoal
  - Shoal— general
  - Intershoal
- Reef
  - Reef Center
  - Reef Talus Apron
  - Reef Debris Apron
- Open Lagoon
- Restricted Lagoon
- Island
  - Island Center
  - Near Island Beach
  - Algal Mat
  - Outer Island Beach
- Tidal Flat
  - Algal Mat
  - Tidal Channel
  - Shallow Sub-Tidal Silty Dolostone
- Supratidal

There are several significantly new features not noted from previous core descriptions. One is the presence of large patch reefs and associated porous debris aprons in the lower Clearfork within sec. 327. Previous work suggested that a "shelf" edge existed to the east of sec. 327 and that the large reefs would only exist along this shelf edge. This new core information implies that there is no shelf edge as such, just patch reefs and debris aprons scattered across the Unit. This information could help explain the erratic distribution of good producing wells in the south-central portion of the Unit. The debris aprons and shoals around these reefs typically have good reservoir quality. In addition, smaller and less-well-developed reefs and bioherms have been noted in the upper portions of the middle Clearfork and upper Clearfork.

Another new piece of information concerns the MF3 layer (±6850 ft) of the middle Clearfork, which has been reinterpreted as a solution collapse breccia with associated open natural fractures. These features were caused by dissolution of carbonate beneath extensive exposure surfaces. The presence of these surfaces is supported by the presence of coal beds, abundant "freshwater" plant debris zones, erosion lag soils, and some root casts. Parts of the Unit were only partially exposed, most probably as a series of small islands and associated carbonate sand beaches. This information is of important economic significance because there is more natural fracturing in the MF3 zone than previously thought. Further analyses will determine the interconnection and influence of this fracturing from solution collapse breccias.

Porosity vs. permeability relationships. Early indications are that, by using multiple geologic "filters," it is possible to dramatically reduce the scatter on porosity vs. permeability crossplots, thereby providing researchers with more robust algorithms. Filters include such devices as depositional environment data, shallowing upward sequence tops, rock type data, mud log data, and numerous open-hole log responses (photoelectric, spectral gamma ray, invasion profile, etc.). Additionally, neural network technology allows the combination of curve data in multiple ways to help find unique permeability signatures. Research has only just begun in this area; however, early results are very promising and will continue.

Special core analysis (SCAL). Approximately 120 preserved (3 in. × 1.5 in.) core plugs were cut from the new whole core in 10-acre infill wells Nos. 1509, 3533, 1510, and 3319 to obtain a representative sampling of all pay rock types defined earlier. Thin-section descriptions and capillary pressure measurements are being obtained from the clipped ends of all 120 core plugs.

The SCAL plugs were further screened both visually (in thin sections and slabbed core) and with a computerized axial tomography (CT) scan machine at Texas A&M University to eliminate the plugs that possessed major barriers to flow (which is almost always in the form of anhydrite nodules), as shown in Fig. 3. A CT number of 2550 and above indicates the presence of extensive anhydrite. Pure dolomite has a CT number of about 2350, and that for pure limestone is around 2250. CT numbers less than 2200 are indicative of good porosity or fracturing.

As the result of these studies, 46 plugs, representing the reservoir rock types (rock types 1, 2, 3, and 5), were chosen for special core studies. The plugs were sent to Core Petrophysics in Tulsa, Okla., for special core analysis. An additional plug screening was performed by obtaining oil permeabilities for all 46 SCAL plugs to determine which samples should be used for relative-permeability tests. Wettability, relative-permeability, capillary pressure, and electrical properties measurements are being performed on the screened plugs to update the database for reservoir flow simulation.

Validation of Reservoir Management Activities and Performance Analysis

Pressure-transient tests. Short-term pressure drawdown tests were used to measure formation flow characteristics in the new producing wells. Drawdown tests rather than buildup tests were recorded to avoid shutting in recently completed wells. These tests were recorded over individual completion intervals (i.e., lower, middle, or upper Clearfork) and were used to estimate the completion efficiency and the relative contribution of each zone to total production.

Both lower (NRU 3534) and middle (NRU 3532) Clearfork drawdown tests in the sec. 329 area and lower (NRU 1509), middle (NRU 2705), and upper (NRU 3018) Clearfork drawdown tests in the sec. 327 infill area have been recorded. The hydraulic fracture jobs have been successful and are producing fractures with half-lengths on the order of 100 ft (skin factor, –5.0). Figure 4 is a log–log plot summarizing the results for the analysis of the NRU 3532 middle Clearfork pressure drawdown test. Results also indicate that the middle and upper Clearfork intervals are much more significant contributors to total production than was previously thought. Each interval's approximate contribution to total oil production appears to be as follows:

	Section 327	Section 329
Upper Clearfork	20%	10%
Middle Clearfork	50%	65%
Lower Clearfork	30%	25%

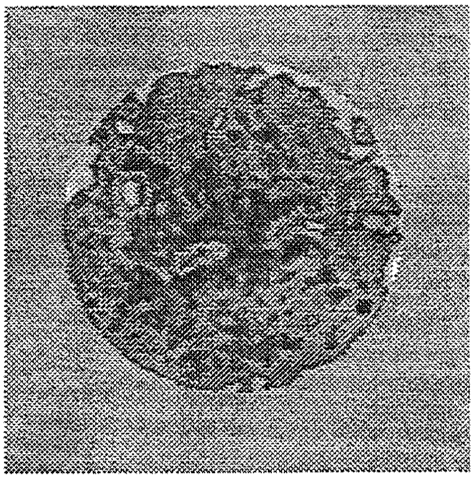
Validation of Reservoir Simulation

Updated reservoir models are being generated.

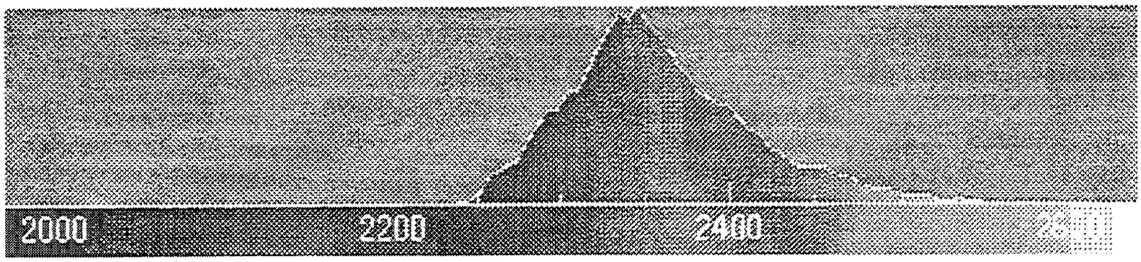
Technology Transfer

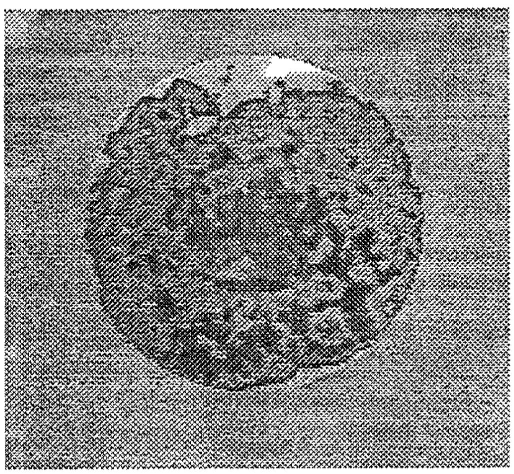
A poster session, "Improved Characterization of Reservoir Behavior by Integration of Reservoir Performance Data and Rock Type Distributions," was presented at the 1997 Annual DOE/BDM International Reservoir Characterization Technical Conference, Houston, Tex., March 2–4.

A paper entitled "Environments of Deposition for the Clear Fork and Glorieta Formations, North Robertson Unit, Gaines County, Texas" was accepted for publication in *Platform Carbonates in the Southern Mid-Continent*, an Oklahoma Geological Society circular.



Fina/NRU 1509
Core No. 13, slice No. 1
Well depth = 7050.8 ft
Min. CT No. = 2218
Max. CT No. = 2687
Avg. CT No. = 2368





Fina/NRU 1509
Core No. 13, slice No. 6
Well depth = 7050.8 ft
Min. CT No. = 2199
Max. CT No. = 2744
Avg. CT No. = 2356

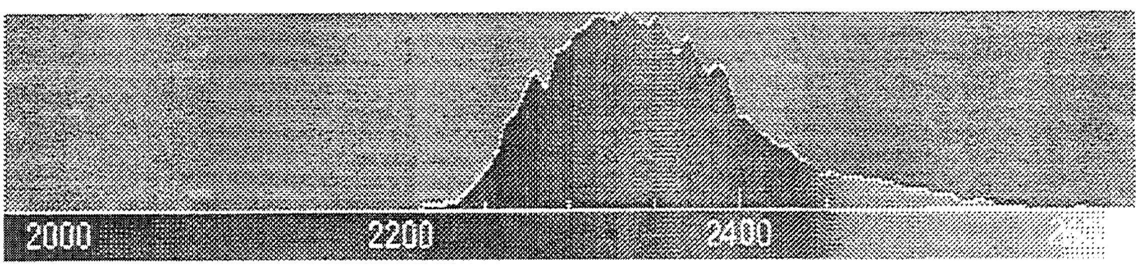


Fig. 3 Computerized axial tomography (CT) images of special core plug from NRU well No. 1509 at 7050.8 ft.

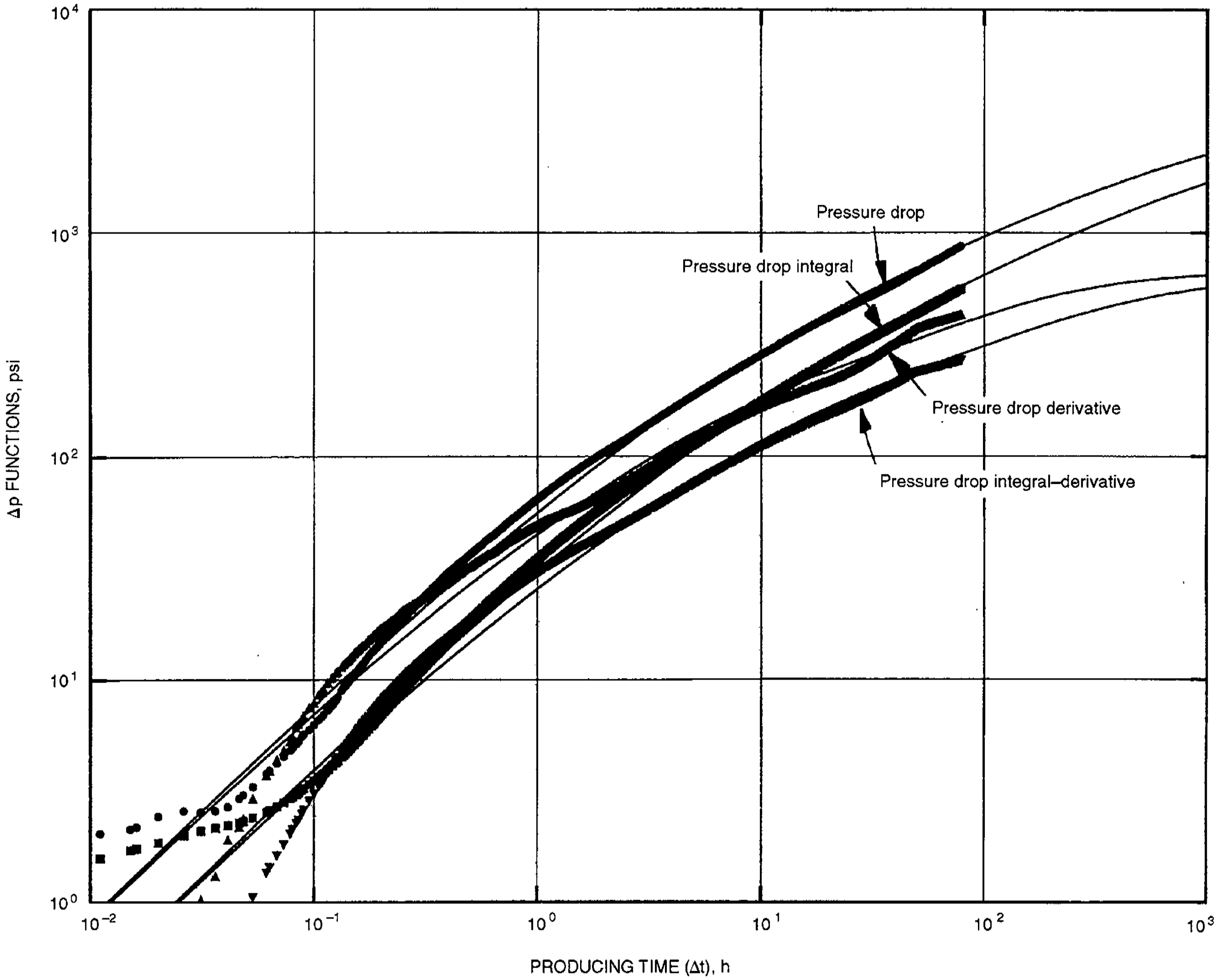


Fig. 4 Data match on log–log plot for well NRU 3532 pressure drawdown test (June 1996). The match was made with the use of the model for a well with an infinite conductivity vertical fracture in an infinite-acting homogeneous reservoir. —, computed solutions. ●, pressure data. ▲, pressure derivative data. ■, pressure integral data. ▼, pressure integral–derivative data.

Data for NRU 3532

(Drawdown test June 1996)

Oil Properties:

B_o = 1.2 RB/STB
μ_o = 2.0 cP

Reservoir Properties:

c_{ti} = 2.0×10^{-5} psia^{-1}
r_w = 0.33 ft
h = 66 ft
ϕ = 0.06 (fraction)

Production Parameters:

q_o = 95 STBOPD
p_{wf} ($\Delta t = 0$) = 1724.0 psia

Results for NRU 3532

(Drawdown analysis—fractured well in a homogeneous reservoir)

k_o = 0.40 mD
x_f = 120.0 ft
C_{Df} = 0.0458
C_{fD} = 1×10^3

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:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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 the 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. When 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

Seismic interpretation continued on the FGU 3-D survey. Work on the seismic attributes of instantaneous phase, instantaneous frequency, and reflection strength is continuing. The next step in the seismic interpretation is correlation of seismic attributes with reservoir attributes such as sandstone thickness, net pay, porosity-feet, and permeability-feet.

Reservoir Characterization

The project is also characterizing heterogeneity of Geraldine Ford and West Ford fields with the use of subsurface logs and cores. All whole cores received from Conoco for this study have been slabbed. Core descriptions from the Conoco archives (3787 ft from 74 wells) are complete. This includes 4 cores from the Ford West field for a total of 172 ft and 70 cores from the Ford Geraldine field for 3615 ft. Sampling and photography will continue, but all representative sampling and photography are complete. The excellent coverage of cores in the Ford Geraldine and Ford West fields provides a unique opportunity to collect diagenetic and stratigraphic data from these cores and identify facies as they relate to the depositional environment.

Reservoir characterization of Geraldine Ford field has integrated data from cores and core-analysis data, outcrop characterization, petrography, and petrophysical data from wireline logs. Ramsey sandstones occur in the uppermost cycle of the Bell Canyon formation and are interpreted to represent progradation, then retrogradation, of an elongate submarine channel and lobe complex formed by sediment-gravity flows on the basin floor. On the basis of core description and field mapping of Bell Canyon sandstones exposed in outcrop 24 miles from Ford Geraldine Unit, the reservoir sandstones are interpreted to consist of sheet-like lobe deposits overlain and incised by lenticular 1000-ft-wide channels. Adjacent levee and overbank deposits vertically and laterally separate channel sandstone bodies. At the northern end of the field, the Ramsey reservoir interval is divided into two layers separated by a low-permeability siltstone. The Ramsey interval is bounded by laterally continuous, organic-rich distal-fan siltstones.

Petrophysical characterization of the Ford Geraldine Unit continued. Most of the wells there were drilled and logged in the 1950s and early 1960s, so special techniques had to be used to maximize the information that could be derived from old logs. Because 80% of the available wells with porosity logs do not have resistivity logs, an indirect method for obtaining water saturation was applied.

Outcrop Characterization

The collection of field scintillometer data and mapping of stratal architecture continued on exposures of the Permian Bell Canyon formation in Culberson County, west Texas. Objectives of this work are to (1) develop a more-detailed interpretation of the stratigraphy and processes responsible for deposition of the Bell Canyon formation; (2) characterize the dimensions and internal arrangement of flow units, baffles, and barriers as seen in outcrop; and (3) establish methods for applying outcrop data to characterization studies in analog reservoirs.

Regionally, the Bell Canyon formation consists of stratigraphic cycles at several scales. At the larger scale, cycles (referred to as intermediate-order) are 50 to 125 m thick and are composed of a sandstone-dominated succession bounded by regionally correlative carbonate mudstones (i.e., Hegler, Pinery, Radar, Flaggy, McCombs, Middle, and Lamar limestones). In turn, these intermediate-order cycles are composed of 3 to 6 high-order cycles bounded by thin organic-rich siltstones. These high-order cycles are 15 to 30 m thick and are composed of an upward-coarsening, followed by an upward-fining, sandstone-dominated succession.

The outcrop work focuses on stratigraphic relationships within basinal deposits of a single high-order cycle. The cycle under investigation is situated near the top of an intermediate-order cycle bounded at the base by the McCombs limestone and at the top by the Middle limestone. The scale and position of this stratigraphic unit within the larger intermediate-order cycle is directly analogous to the Ramsey interval in the Geraldine Ford field, which occurs in an equivalent position in the intermediate cycle below the Lamar limestone.

Field work has been concentrated at the two study areas, Willow Mountain and Wild Horse Draw. At Willow Mountain, exposures are several kilometers in length and are aligned perpendicular and parallel to the depositional strike of the system. Photographs of the outcrops have been assembled into photomosaics. Twenty-four sections have been measured, described, correlated, and assembled into cross sections. The cross sections establish the dimensions, geometry, and stacking pattern of interpreted submarine lobe and channel-levee complexes. The internal architecture within a single channel-levee system is documented in detail from exceptional exposures located in Wild Horse Draw.

Preliminary interpretations of the stratigraphy and lithofacies indicate the presence of several large channel-form sandstone bodies. These sandstone bodies are elongate in a north-south direction and display a broad, funnel-shaped geometry that is up to 20 m thick and several hundred meters wide. The channel-form bodies are incised into upward-coarsening successions of lutite, siltstone, and sandstone that are 1 to 5 m thick and have a sheet-like geometry. The channel-form bodies show evidence of lateral migration and are bounded by lenticular fine-grained deposits interpreted as channel levees. In a basinward direction, the channels bifurcate and are flanked by laterally extensive, sheet-like sandstones interpreted as submarine lobes. Within the high-order cycle, submarine lobe and channel-levee complexes initially step basinward and then aggrade and finally retrograde.

Gamma-ray measurements were also made along many of the measured lithologic logs. Gamma logs are used by geologists to evaluate lithology and correlate strata between subsurface wells. Outcrop-derived gamma logs provide a link between what is observed on outcrop and what is interpreted with well logs. Comparisons of outcrop gamma logs with maps of stratal architecture generate a better understanding of correlation techniques and their pitfalls. A total of 20 gamma-ray logs have been collected from the Willow Mountain and Wild Horse Draw case studies areas. Each traverse spans the entire high-order cycle and consists of 120 to 160 measurements. The traverses were selected to encompass the majority of lithofacies present within the submarine lobe and channel-levee system.

Producibility Problem Characterization

A summary of well completion histories has been entered into a spreadsheet. Initial potentials for oil (bbl of oil per day), gas (thousand cubic feet per day), and water (bbl of water per day) are entered for more than 300 wells in the Ford Geraldine Unit. These data will be transferred into Landmark StratWorks to map initial potential and compare it with sandstone thickness, porosity, and permeability.

Recovery Technology Identification and Analysis

Work began this quarter to develop a detailed permeability model for the demonstration area of the Ford Geraldine Unit generated by conditional simulation. In this technique, the generated field honors the measured data, follows a desired correlation structure, and maintains reasonable heterogeneity.[1–4] This geostatistical model will be used as an input for reservoir simulations of the demonstration area to evaluate the fluid-flow performance of the reservoir.

In the demonstration area, core permeability data are available for 21 wells with a total of 722 measured permeability values. These data were analyzed for their distribution type, correlation structure, and statistics. The cumulative distribution function (CDF) of the permeability data in Fig. 1 on log-probability coordinates shows the data plot almost as a straight line. This is an indication that the permeability data in this field are approximately log-normally distributed. The mean and the standard deviation of natural-log permeability are 2.38 and 1.85, respectively. The resulting coefficient of variation of 0.77 indicates that heterogeneity is of moderate degree.[5]

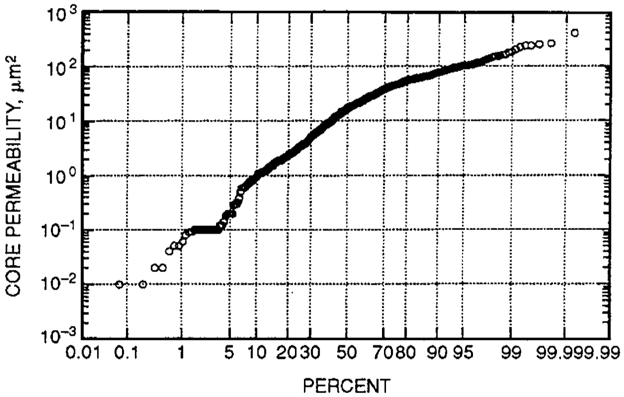


Fig. 1 Cumulative distribution function for core permeability from 21 wells in the northern part of Ford Geraldine Unit.

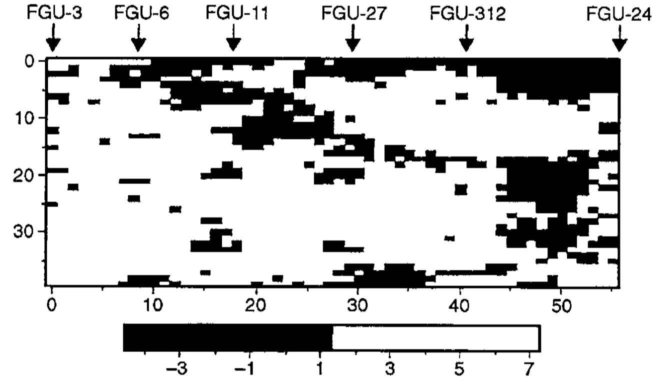


Fig. 2 Permeability cross section (56 × 40 blocks) by conditional simulation using spherical semivariogram with dimensionless correlation length of 0.3. The scale is natural-log-(mm²).

So that the autocorrelation structure could be determined, semivariograms of permeability as well as the log permeability were plotted for the cored wells. Rescaled range plots [2,4] were also made to investigate the possibility of a power-law or fractal autocorrelation structure. The results did not indicate a well-defined autocorrelation structure. Data in many wells indicated a spherical semivariogram, whereas a few wells appeared to support the possibility of a fractal semivariogram. Both types of semivariograms were tested in two vertical cross sections, and the resulting permeability distributions were evaluated in conjunction with the geologic model of the reservoir. Results indicated that a spherical semivariogram with a dimensionless correlation length of 0.3 is a preferable model for geostatistical permeability distribution in this field. A permeability image for a 56 × 40 block cross section generated by using a spherical semivariogram is shown in Fig. 2. In this figure the heterogeneity is realistic, extreme values are not predominant, and the low-permeability laminated siltstone within the Ramsey reservoir interval is reasonably represented by continuous low permeabilities in the middle horizontal portion. The CDFs of the generated and conditioning data also matched closely.

The demonstration area of the field requires about 66,000 blocks for 3-D permeability distribution. This is based on a 150-ft block size in each of the two horizontal directions x and y and 1 ft in the vertical z direction. A program based on the matrix decomposition method [6,7] is being used to generate the 3-D permeabilities. This method involves the inversion of a full matrix that is computationally intensive and time consuming. Therefore the permeability distributions are being generated in separate parts, each consisting of about 10,000 blocks.

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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

Principal Investigator:
Mark B. Murphy

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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 plan includes the development of a control area with standard reservoir management techniques while comparing its performance to an area developed with advanced reservoir management methods. Specific goals are to (1) demonstrate that an advanced development drilling and pressure maintenance program 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 throughout the U.S. oil and gas industry.

Summary of Technical Progress

Management and Project Planning

Geological, engineering, geophysical, and simulation teams continued compiling and analyzing data. Data were entered into the geological model, and a preliminary reservoir simulation run was performed. The three-dimensional (3-D) seismic data are being interpreted and areas have been identified for targeted drilling.

Geology

Geologic Model

The geologic model has been refined to meet the geological and reservoir engineering constraints necessary to begin the simulation. Much time has been spent "fine tuning" the model. The simulation team began the initialization phase and the equilibration of the model in the pilot area. Problems with the volumetrics in the pilot area necessitated modifying the geologic model. The subunits for the L sand and the individual structure maps were remapped in greater detail, and the net pay maps were revamped. After completion, the areal extent of the reservoirs was sufficient to accommodate the volume necessary to proceed with the simulation.

Geologic Interpretation of Seismic Data

As the result of the interpreted 3-D seismic data volume, thoughts regarding the distribution of pay sands in the K and L sands have shifted. The focal points of deposition of the higher quality reservoir facies have shifted to the northern part of the unit. Consequently the relationship of this distribution to the underlying Bone Spring Limestone needs to be examined more closely. The concentration of better quality reservoir rock may be related to the underlying Bone Spring topography, which is the area currently being investigated.

Engineering

Data Acquisition Well

Nash Draw well No. 12, located at 918 ft from the south line and 2153 ft from the east line of sec. 12, T. 23 S., R. 29 E., was successfully completed. Initial production tests show daily production rates of 75 bbl of oil per day, 250 mcf of gas, and 240 bbl of water. The well is flowing up the annulus and is capable of higher production rates. The majority of the water is producing from the high-permeability, wet K-2 zone.

This well exhibited good L zone development and fair K zone development. The correlation of porosity in the K and L sands with the high-intensity seismic reflection amplitudes for the respective intervals in the 3-D seismic data volume presents positive information that seismic attributes correlate to the best quality reservoir rocks in the Nash Draw Unit.

Pilot Area

The proposed pilot area around well No. 1, including well Nos. 1, 6, 14, 5, 9, and 10, is being reviewed. Detailed flow-unit maps have been prepared. Each of the subunits of the three main sands has been mapped individually: Isopach maps for log-derived net pay and isopach maps for gross subunits. These maps have been put into the geologic model for the reservoir simulation study in the pilot area.

Comparison of the seismic lines and time slices has shown some evidence of discontinuities in the area surrounding well No. 1. This indicates that the area may be compartmentalized, and the lateral continuity between the pilot wells could be reduced. Further study of this discovery is needed to determine the viability of the proposed pilot area. The 3-D seismic indicates that other areas may be better suited for the initial pilot area.

E. Loving Analogy

So that the recovery techniques used in this project could be evaluated, an analog area was selected and analyzed to determine the recovery efficiency and producing characteristics of a field completed with the use of standard techniques. An entire 640-acre section in the Loving Brushy Canyon Pool was selected as a typical primary producing model. Sec. 14, T. 23 S., R. 28 E. was selected because it was fully developed on 40-acre spacing, offered a wide variety of geological conditions, and had sufficient production history to predict recoveries reliably. Sec. 14 contains the typical components of a Delaware pool: It dips from west-northwest to the east, the northwest corner is at –3107 ft at the top of the Bone Spring formation, and the east edge is at –3261 ft.

This is a change of 254 ft in the structure across the section. A bench in the middle of the west side of the section has a lower dip angle than the steps on either side of the bench. Production associated with sands deposited on the bench is considerably higher than wells located on the steps.

Sec. 14 has a bench that is approximately 0.5 mile wide with steeply dipping steps on either side. The step-bench sequence is a typical depositional characteristic of the Basal Delaware zones in this area. Wells located on the bench in sec. 14 have significantly higher recoveries than those located on the updip or downdip step.

Comparison of data from the Nash Unit and Loving Field helped confirm that reservoir characteristics were similar between areas. Core data were obtained from the wells in Loving Field, and the distribution of porosity vs. permeability was compared and found to be very similar. Also, producing characteristics, oil saturations, and rock properties are in close agreement. The single most important difference between the two areas is in the K-2 zone. The Nash has a highly developed K-2 zone that is wet and produces large volumes of water if stimulated. The Loving wells do not have a significant K-2 zone and produce small quantities of water.

So that the ultimate primary recovery from this section could be predicted, a production curve was created for each well displaying oil, gas, and water historical production. From this production history, decline curves were described for each phase and projected to the economic limit to calculate the ultimate recovery from each well. The projected primary recovery from each well was estimated from the decline-curve analysis, and the total primary recovery from the 16 wells in sec. 14 is projected at 2,084,013 bbl of oil, 10,981,608 mcf of gas, and 976,669 bbl of water.

For the original-oil-in-place (OOIP) estimate, a core-calibrated log analysis was performed to determine the actual net pay from a digitized log. With the use of digitized logs with 0.5-ft sampling, the resolution to determine productive zones in the highly laminated Delaware zones is provided. After the pay zones, saturations, and permeabilities were determined, a volumetric calculation was performed to determine the oil in place at each wellbore.

From a comparison of these two methods of analysis, good agreement was found between the two calculations (see Table 1).

The values shown in Table 1 will be used to analyze the techniques used at the Nash Draw Unit. With better stimulation, targeted drilling, pressure maintenance, and reservoir characterization, recoveries at Loving Pool should be better than the 16.7% realized.

TABLE 1

Comparison of Oil and Gas Recoveries

	Volumetric analysis	Material-balance calculation
Original oil in place, bbl	12,473,340	12,467,072
Oil recovery,%	16.71	16.77
Original gas in place, mcf	12,722,807	12,716,413
Gas recovery,%	88.04	

Delaware Data

Texaco has drilled five wells offsetting the Nash Unit in the southeastern corner of the Nash Draw Unit (NDU). Log and core data were obtained for analysis and inclusion into the NDU database. The L zone is the main pay zone in the Texaco wells, which is similar to the NDU wells; the K-2 zone is wet and produces large quantities of water; and the K zone is lower structurally and is wet. The "L" zone exhibits similar porosity–permeability relationships in both areas. Permeability is slightly lower in the K-2 zone in the Texaco wells, and the permeability is slightly higher in the K zone.

The wells in the Texaco area are deposited on a bench-step surface on top of the Bone Spring zone, which is similar to other Delaware fields in the area. The top of the Bone Spring zone on the west edge of sec. 19 is at a depth of 6830 ft (common datum) and the east edge is at a depth of 6950 ft. This represents a dip of 120 ft across the north end of the section. The bench is approximately 0.5 mile wide, and the steps are approximately 0.25 mile wide.

The Texaco wells were completed in the first half of 1996; therefore sufficient production history is not available to make an accurate prediction of ultimate recoveries from decline-curve analysis.

A volumetric estimate of the OOIP was made by assigning the oil-in-place value for 0.4-acre grid blocks for the 640-acre section. With the use of this analysis, the section contains 2,954,648 bbl of oil, with 493,526 bbl in recoverable reserves with a recovery factor of 16.7%. The recovery for each well, based on drainage areas, is shown in Table 2.

TABLE 2

Estimated Recoveries Based on Drainage Areas

Unit	Primary oil recoveries, bbl	Acres
A	92,151	72.0
B	59,182	64.0
C	49,942	57.6
F	53,152	70.4
K	50,209	83.2
Total	305,636	347.2

Because of thinner pays, a narrower bench, and the L zone as the only pay, the Texaco wells have approximately half the primary reserves as the NDU wells. Also, the very wet K-2 zone contributes large quantities of water if fracture stimulated with the L zone.

3-D Seismic

A seismic profile extending across the central part of the Nash Draw 3-D grid illustrated the conformability relationships between the two reference chronostratigraphic surfaces selected for the Nash Draw interpretation (the top of the Bone Spring and the shallower CRS event) and the stratigraphically adjacent K and L Brushy Canyon reservoirs.

Because the easily interpreted Bone Spring and CRS surfaces are conformable to the difficult-to-interpret K and L thin-bed reservoirs, thin analysis windows that exactly span the K and L units can be properly positioned in the 3-D seismic volume by defining sequence boundary surfaces that are offset from the Bone Spring and CRS reference surfaces by a constant (conformable) distance across the complete 3-D image space, that offset distance being determined by the vertical seismic profile (VSP) calibration data recorded in the nearby No. 25 well.

Herein lies the importance of establishing a high degree of conformability between a targeted, but poorly imaged, thin bed and a nearby robust chronostratigraphic reflection surface; therefore, when conformability does occur, an accurate analysis window, which spans the thin bed, can be defined even if it is difficult to see. Analysis of the east-west cross-line profile supports the assumption that the L sequence is conformable to the top of the Bone Spring and that the K sequence is conformable to the CRS peak.

The VSP calibration data acquired in well No. 25 established that (1) the top of the Bone Spring limestone was a robust reflection peak at 1.0 s (at the 25 well), (2) the L sequence that dominates production at Nash Draw field was associated with the first reflection trough immediately above this Bone Spring peak, and (3) the K sequence began at, or just above, the first reflection peak above the Bone Spring event. Inspection of the 3-D data volume showed that the L reflection trough had a highly variable amplitude and wave shape and was associated with a number of distinct seismic facies across the image space. Regardless of the depositional facies exhibited (concordant, downlap, mounded, or chaotic), the L reflection trough never rose higher than 16 or 18 ms above the Bone Spring.

Because of this approximate conformability between the L reflection trough and the robust Bone Spring reflection peak, the amplitude of the L reflection trough was defined in every bin of the 3-D volume by determining the maximum negative amplitude value in a data window that was bounded at the base by the Bone Spring reference surface and at the top by an arbitrary surface defined as Bone Spring-18 ms.

A map of these maximum negative reflection amplitudes across the total 3-D seismic image space displayed a strong visual correlation between the areal distribution of the high-amplitude L reflections and the positions of the better producing wells (well Nos. 19, 11, and 15) documents an important principle that should be considered when siting future Nash Draw wells: *As the amplitude of the L reflection trough increases, the productive potential of the L sequence increases.*

There is a strong, positive correlation between the amplitude of this reflection trough and the productivity of the Nash Draw wells. Wells 11, 13, 15, 19, and 24 are the best producers in Nash Draw field, and the amplitude of the L reflection trough is a maximum along the trend where these wells are located, although the trend does not quite extend to well 24. The amplitude behavior near well 13 should be ignored because this well location is not properly imaged because of surface contraints imposed by the large salt lake in the north-central portion of the NDU. Wells 9, 23, and 25 are the poorest producers in the field, and the amplitude of the L reflection trough has its minimum values near these well sites. Well Nos. 1, 4, 5, 6, 10, 14, and 20 are modest producers, and the L reflection trough has intermediate amplitudes and a patchy behavior around these wells. Thus higher amplitudes of the L reflection trough imply better well productivities.

A map of the amplitude of the K reflection peak looks much like the L reflection trough map with higher reflection amplitudes again occurring at the better producing locations.

The correlation between well performance and the L reflection amplitude can be expressed in a quantitative way that reservoir simulators can use to numerically calculate critical fluid-flow parameters from the 3-D seismic amplitude volume. In particular, statistically significant linear relationships have been established between reflection amplitudes of the "L" sequence and three critical L reservoir properties: Reflection amplitude and net pay, reflection amplitude and porosity-feet, and reflection amplitude and transmissivity to oil and water.

Crossplots of the relationships among these parameter pairs were used to obtain the best-fit straight line developed by linear regression to describe the distribution of the respective data populations.

Reservoir Characterization/Reservoir Simulation

Activities of the Reservoir Characterization/Simulation Team for this quarter were focused on the initialization of a reservoir simulation model of the oil lobe that supports the pilot area wells (Nash wells Nos. 1, 5, 6, 10, and 14).

During the quarter the engineering and geology teams developed a new interpretation of this lobe that incorporates, for the first time, data from the recently acquired 3-D seismic survey. With the use of seismic amplitude as a guide, the pilot lobe was recontoured. In this interpretation, the pilot lobe occupies about 300 acres. Figure 1 contrasts this new interpretation with the previous one (Fig. 2) for the top of structure of the uppermost horizon, the J sand.

With the use of the Well Attribute model developed last quarter, the following attributes were imported into the stratigraphic framework model for the L sand of the pilot lobe: Interpreted porosity, interpreted permeability, and water saturation. The L sand produces more than 90% of the oil from the pilot area, and the K-2 sand is responsible for most of the water production.

In some instances these attributes were available on a foot-by-foot basis for one or more of the producing zones. All of the attributes were available for each well identified. The distribution of reservoir attributes like conductivity and storage capacity within the producing zones of the Nash Draw Brushy Creek Unit was based on the well attribute model. Within the Stratigraphic Geocellular Model, these distributions are weighted by the reciprocal of the square of the distance between the location of interest and nearby wells within the reservoir model.

The present model is adequate to represent the geology of the Nash Draw Brushy Canyon pilot for reservoir simulation. A simulation model has been constructed to reflect this latest characterization, which includes a description of the reservoir fluid property data (differential vaporization experiment), special core analysis data (for a sample taken from Nash No. 19), initial reservoir fluid saturations and datum pressure, and production and well test data for all the wells in the pilot area.

This model consists of twenty layers. This resolution is the minimum required to capture the thin beds of the L sand. The areal dimensions of the grid blocks are approximately 1 acre. The OOIP for the pilot is in close agreement with engineering estimates: Engineering value, 3.591×106 stock tank barrels (STB); geological model, 3.606×106 STB; and simulation model, 3.572×106 STB.

Technology Transfer

Transferring technical information generated during the course of this project is a prime objective of the project. Toward this objective, Strata has participated in several meetings and workshops to promote the dissemination of information generated during this quarter.

A liaison committee meeting was held on Dec. 18, 1996, to update the Director of the New Mexico Oil Conservation Division as to the status of the project and findings to date.

One of the pertinent technology transfer objectives was the rapid dissemination of the technology that had a direct influence on the characterization of the Nash Draw field. Toward this objective, the New Mexico Petroleum Recovery Research Center embarked upon creating an Internet home page specifically dedicated to the Nash Draw project. This home page is at http://baervan.nmt.edu/prrc/resdiv/react/reactnew.html. This address accesses the REACT (Reservoir Evaluation and Advanced Computational Technologies) home page. By clicking on the REACT PROJECTS section, the NASH DRAW project can be accessed.

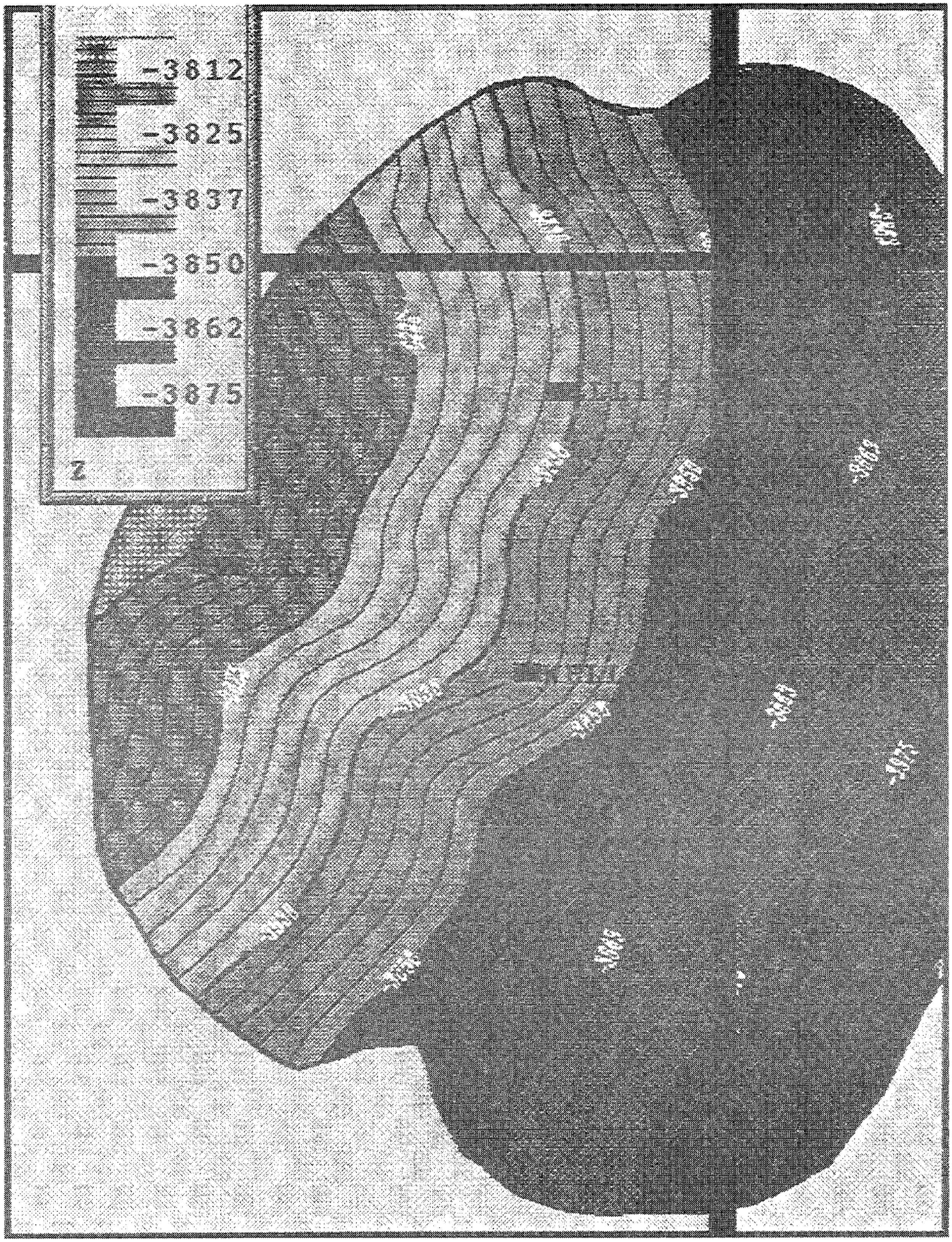

Fig. 1 New interpretation of structure in the Nash Draw pilot area. (Art reproduced from best available copy.)

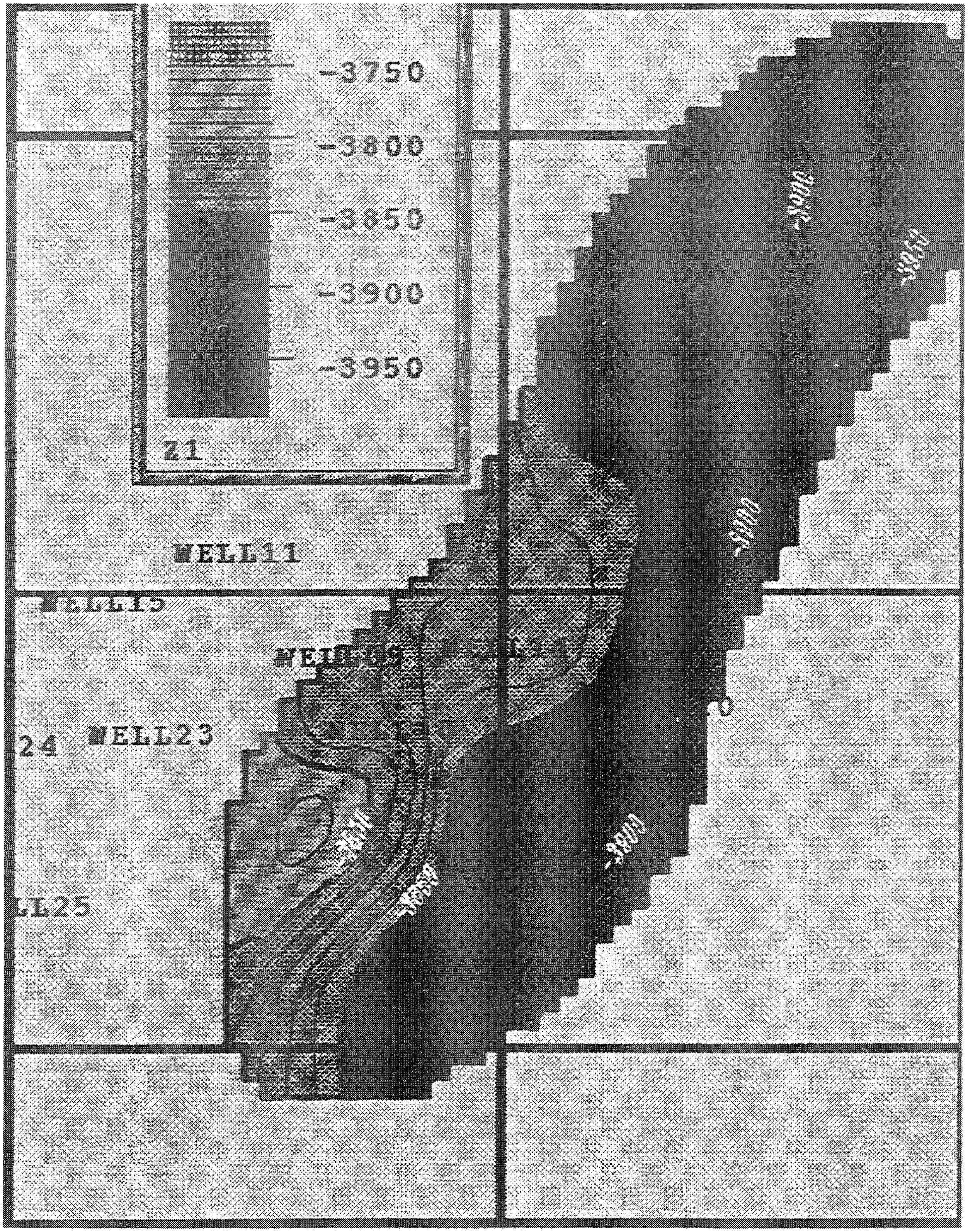

Fig. 2 Interpretation of structure in the pilot area prior to availability of 3-D seismic data. (Art reproduced from best available copy.)

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
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 31, 1996

Objectives

The main objective of this project is to address waterflood problems of the type found in Morrow sandstone reservoirs in southwestern Kansas and Cherokee group reservoirs in southeastern Kansas. Two demonstration sites operated by different independent oil operators are involved in the project. Stewart field, located in Finney County, Kans., is operated by North American Resources Company. The Nelson lease, located in Allen County, Kans., in northeastern Savonburg field, is operated by James E. Russell Petroleum, Inc.

General topics to be addressed are (1) reservoir management and performance evaluation, (2) waterflood optimization, and (3) the demonstration of recovery processes involving off-the-shelf technologies that can be used to enhance waterflood recovery, increase reserves, and reduce the abandonment rate of these reservoir types.

In the Stewart field project, Budget Period 2 objectives consist of the design, construction, and operation of a field-wide waterflood with the use of state-of-the-art, off-the-shelf technologies in an attempt to optimize secondary oil recovery. To accomplish these objectives, the second budget period was subdivided into five major tasks: (1) design and construction of a waterflood plant, (2) design and construction of a water injection system, (3) design and construction of tank battery consolidation and gathering system, (4) initiation of waterflood operations and reservoir management, and (5) technology transfer. Work this quarter was focused on items 4 and 5.

In the Savonburg field project, Budget Period 2 objectives consist of continual optimization of this mature waterflood in an attempt to optimize secondary and tertiary oil recovery. To accomplish these objectives, the second budget period was subdivided into six major tasks: (1) water plant development, (2) profile modification treatments, (3) pattern changes and wellbore cleanup, (4) reservoir development (polymer flooding), (5) field operations, and (6) technology transfer.

Summary of Technical Progress

Stewart Field Project

Waterflood Operations and Reservoir Management

Production on the Haag Estate No. 2 (which had multiple casing leaks over a long interval and was being pump tested beneath a packer) did not get better than 0.5 bbl of oil per day (BOPD) and 15 bbl of water per day (BWPD), so the well was shut in to evaluate offset drilling options.

The Sherman No. 5 (which had been shut in since late January 1996) was placed back on production with a progressive cavity pump. The Sherman No. 5 was producing 3 BOPD and 170 BWPD when it was shut in. The high water production is due to fracture communication between the Morrow and a primarily water-producing Mississippian formation. The progressive cavity pump was designed to produce over 500 bbl of fluid per day and was installed in an attempt to lower the fluid level to allow the Morrow to produce into the wellbore. The well was placed on production on Nov. 26, 1996, at a rate of approximately 9 BOPD and 220 BWPD during the last five days of November. Production from the well tested at 330 BWPD and 14 BOPD at the beginning of December and was increased to a semistable near pumped-off rate of 385 BWPD and 25 BOPD at the end of December.

A larger bottom-hole pump, rods, and a larger pumping unit were installed on the Bulger No. 7-4 on Dec. 27, 1996, to lower the fluid level that had increased over the previous few weeks. Production before installation of the larger lift equipment was 135 BOPD and 8 BWPD; postinstallation tests have been as high as 240 BOPD and 15 BWPD.

The monitoring of production, injection, and water supply volumes and pressures continued. Ongoing testing of producing wells with test trailers and fluid-level guns also continued. Oil production increased approximately 450 BOPD during the quarter because of waterflood response, which brings the total increase to approximately 1050 BOPD. Ongoing allocation of injection volumes in injection wells will be based on response in producers and injectors. Daily production and injection rates for the Stewart field are shown in Fig. 1. A fall-off test was run on the Meyer No. 10-2 injection well.

Well servicing was performed as necessary (e.g., pump changes, minor well work, and speed-up pumping units). The Carr 2-2 WSW submersible pump was pulled in October because of a hole in the tubing. The tubing string was changed

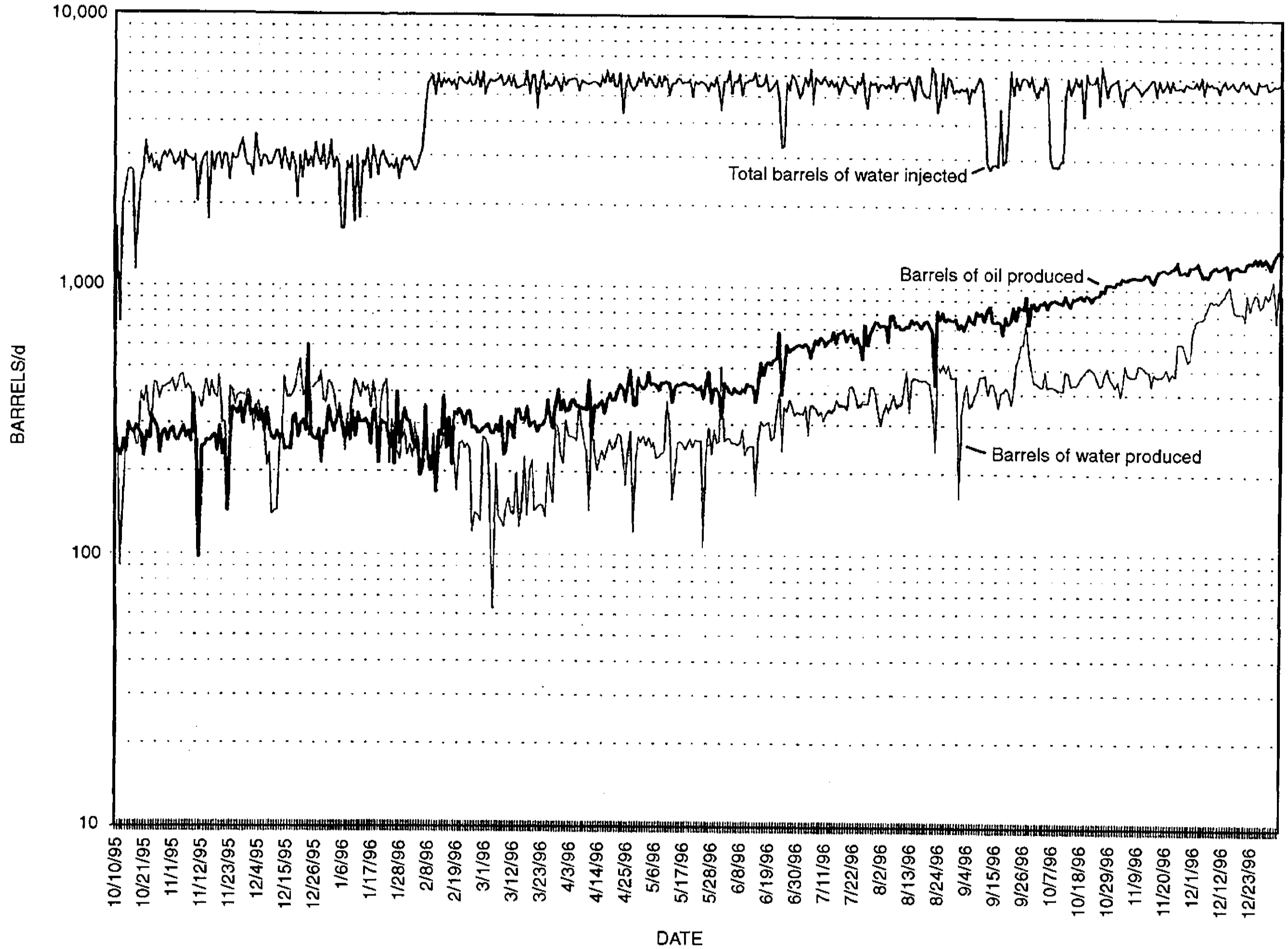

Fig. 1 Stewart field waterflood daily totals.

out because of pitting by under deposit (iron sulfide) corrosion. Quarterly chemical treatments will be administered on the WSW to help with this problem.

The electrification of Stewart field was completed during November. The only wells that were not electrified in the field are three current producers (Meyer No. 10-5, Carr No. 2-1, and Scott No. 4-7) that are planned as future injectors and two wells (the Haag Estate Nos. 1 and 2) that were tested and abandoned.

Technology Transfer

An article was published in the *University of Kansas Petroleum Technology Newsletter* for the fourth quarter of 1996.

Stewart field project results to date were presented at the Tertiary Oil Recovery Project's advisory board meeting on Oct. 2, 1996.

Operators throughout the area continue to visit the field to view the state-of-the-art waterflood installation and computerized monitoring system.

Savonburg Field Project

Water Plant Development

A severe bacteria infestation was confirmed by inoculation testing of injection water on Oct. 2, 1996. The corrosion coupons were pulled and the trunk lines flushed and cleaned. The slop tank and filter tank [air flotation unit (AFU) discharge tank] were both cleaned, and 55 gal of bleach was added to the filter tank while filling. The system was treated by adding another 110 gal of bleach to the produced water and mixed water tanks. The system was then flushed and all wellhead filters changed. Inoculation tests taken for bacteria on Oct. 25, 1996, do not appear favorable. Preliminary indications are that the bacteria problem persists.

The second set of corrosion coupons had only 3 weeks exposure but appeared to confirm rather severe corrosion at various points in the injection system. Oxygen measurements are being made, and possible mitigation methods are being studied.

The air turbine units in the air flotation unit continued to give problems with scaling and leaking seals. Two of the turbine units were pulled, cleaned, and repaired on Oct. 4, 1996. Late in October, a new air compressor and bubble-generating device were installed and tested.

A new type of venturi device for bubble generation was successfully installed and tested. It appears to offer promise of further improvements and efficiency in the cost of operating the AFU. Further testing is planned.

Profile Modification Treatments

Two important channel-block jobs were accomplished during the quarter. Another 60-bbl job was done on well H-14 on Oct. 16–17, 1996. An identical 60-bbl treatment was administered to well H-5 on Oct. 30–31, 1996. Mechanical aspects of mixing and placement were excellent on both jobs. Offset producing wells are being tested and results evaluated.

Pattern Changes and Wellbore Cleanup

Well KW-6, a key B3 injection well, was cleaned and stimulated. The well was washed clean, jetted with the pump truck, and treated with 90 gal of acid plus additives. A bottom-hole sample was collected and is being analyzed at the University of Kansas. The new injection well, RW-20, was shut in for a pressure fall-off test.

Well O-1 was washed, jetted with the pump truck, and acidized with 100 gal of acid plus additives. The data logger and meter were moved from well H-5 to well RW-20 in preparation for a pressure fall-off test.

In October the following wells were serviced: H-21 (twice), H-22 (twice), H-10, H-16, and H-17. In November the following wells were serviced: H-20 (twice), K-43 (twice), H-22, K-45, and H-16. In December the following wells were serviced: H-16 (twice), H-13 (three times), H-3, and H-21. All jobs were caused by holes in the pump strings.

Field Operations

Normal field operations have included monitoring wells on a daily basis, repairing water plant, 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.

TABLE 1

Savonburg Field Oil Production

Month	Oil production, BOPD	Month	Oil production, BOPD
October 1993	26.4	June 1995	23.9
November 1993	30.7	July 1995	26.8
December 1993	32.0	August 1995	25.2
January 1994	30.8	September 1995	24.8
February 1994	30.9	October 1995	24.4
March 1994	30.3	November 1995	24.4
April 1994	29.1	December 1995	26.3
May 1994	28.5	January 1996	29.0
June 1994	30.3	February 1996	29.2
July 1994	28.9	March 1996	27.2
August 1994	24.6	April 1996	26.7
October 1994	23.0	May 1996	26.6
November 1994	25.7	June 1996	24.9
December 1994	27.8	July 1996	25.4
January 1995	27.0	August 1996	26.5
February 1995	25.3	September 1996	26.1
March 1995	22.4	October 1996	27.1
April 1995	22.4	November 1996	26.4
May 1995	25.0	December 1996	27.8

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
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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

Reservoir Characterization

The TOW No. 1-3 demonstration well in Crystal field is currently producing at the 100 bbl of oil per day (BOPD) level and has produced 37,528 bbl of oil through December 1996 (Fig. 1). The water cut remains at 0%, and pressure has been maintained at 1445 psi by an active water drive.

Cronus Development Co. drilled another horizontal well at Crystal field, the Frost No. 5-3, as a follow-up to the TOW No. 1-3 (Fig. 2). This well achieved the planned lateral length of 1900 ft and is currently being tested. Some lost circulation occurred in the Frost No. 1-3, and this fluid is currently being returned on test. Underbalanced drilling, in which the formation is allowed to flow during drilling, was not used, although project researchers strongly recommended its use.

Core and Log Analysis

X-ray-diffraction analyses of samples from the TOW No. 1-3 core collected on a foot-by-foot basis during this quarter were completed. Also, selected core samples of dolomitized Dundee reservoir recovered from other fields in central Michigan were x-rayed.

Data Measurement and Analysis

Several two-dimensional (2-D) seismic lines over the Crystal field, run in 1987 by a major oil company, have been received for research and teaching use. COCORP data obtained in Michigan in the late 1970s have also been received. The COCORP lines do not cross Crystal field, but at least one intersects the proprietary data, so calibration between lines should be possible.

Production data for the 30 project fields is now available to the public on the Internet at either http://www.geo.mtu.edu/svl/michproj/ or http://www.wmich.edu/geology/corelab/coreres.htm.

Database Management

Dundee Atlas

With the use of GeoGraphix software and the Angstrom Precision Corp. database, a series of isopach maps was produced encompassing all the formations in the Michigan Basin. Of the 50 formation isopachs produced, only 9 were made with the use of data from fewer than 1000 wells. A second series of isopach maps was produced on the basis of formation ages. Of the 13 isopachs produced, 4 were created with the use of data from fewer than 1000 wells. A project is under way to produce a complete series of structure contour maps for all the formations in the basin. Roughly 50% of the structure maps are complete.

The electronic *Atlas of Michigan Dundee Reservoirs* is now under way. This project presently includes a regional overview of Dundee structure, thickness, and production history for about 20 fields.

Pseudoseismic Visualization

MatLab programs to visualize the Michigan Basin in two (2D) and three dimensions continue to be developed. This past quarter, two "M-files" were written.

- *hist2D* subdivides an area bounded by given lat-long coordinates into a user-controlled grid size and determines the number of elements in grid element as well as the minimum, median, and maximum values. This is useful for taking the lat-long coordinates of a large number of wells and determining the number of wells in a specified lat-long box as well as the minimum, median, and maximum values of, say, formation tops.
- *interp2D* takes the output from *hist2D* and fills in missing data by 2-D interpolation.

In this manner, it is possible to reduce the large Angstrom dataset (50,000+ well), which tends to be severely clustered (i.e., many wells in small region), to a more manageable

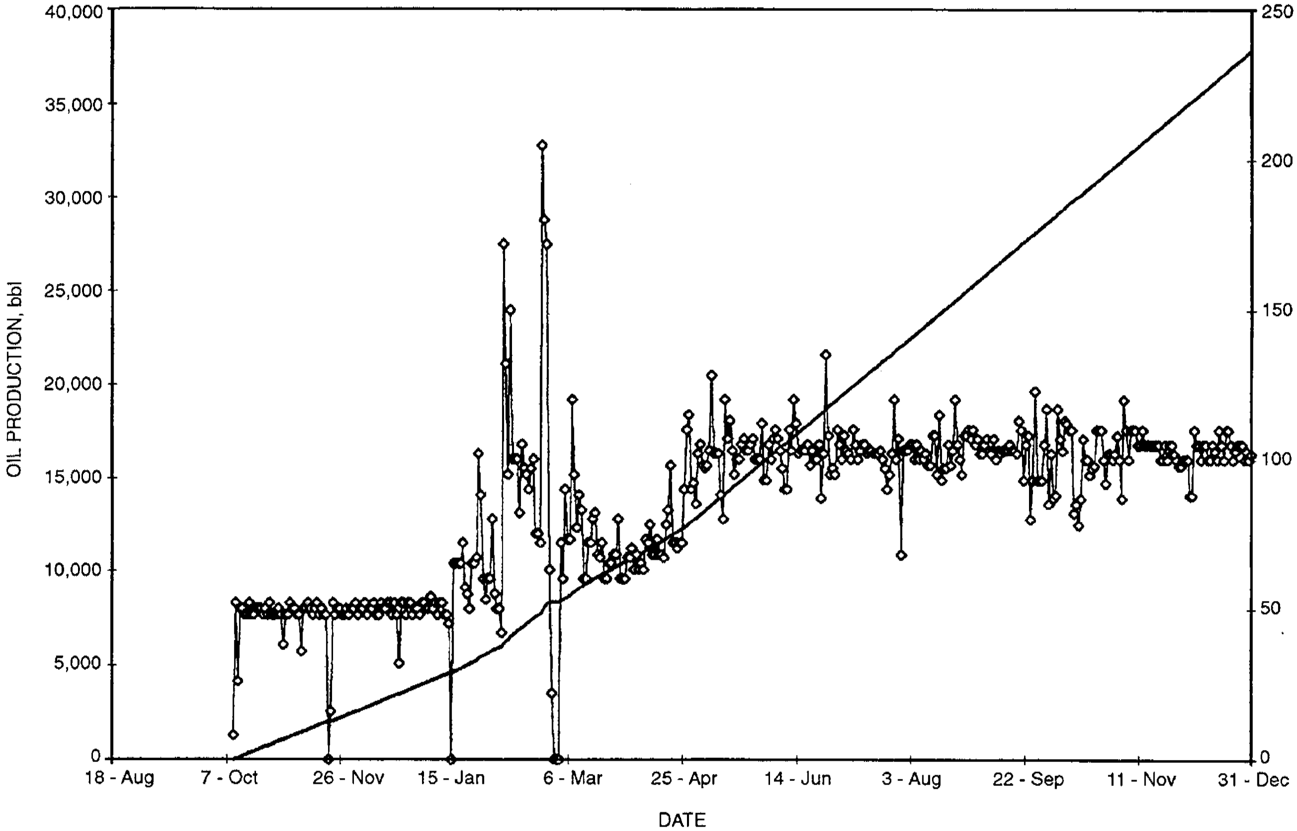

Fig. 1 Production history for the TOW No. 1-3 horizontal well at Crystal field showing daily and cumulative production for Oct. 7, 1995, to Dec. 31, 1996. —, cumulative. —◇—, daily.

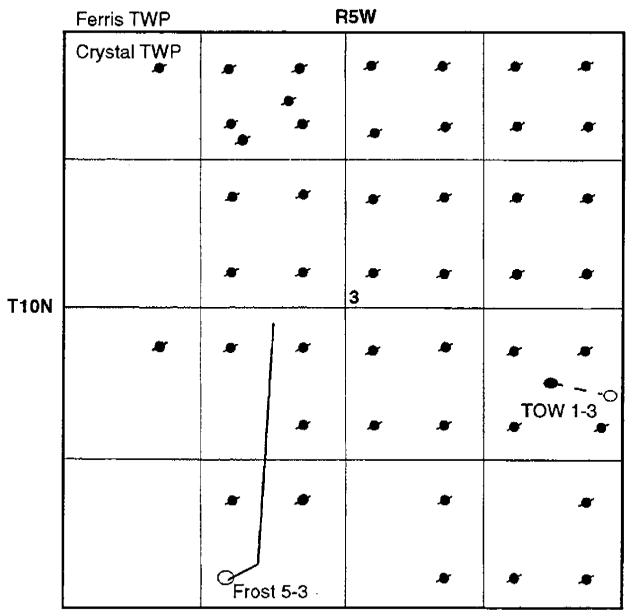

Fig. 2 Location map showing sites for the new horizontal well drilled at Crystal field in December 1996. The first horizontal well (the TOW No. 1-3) is shown by the dashed line in the block labeled "TOW 1-3." Symbols show locations of development wells.

subset that covers the entire state and permits rapid construction of structure and isopach maps in such programs as GeoGraphix and MatLab.

The MatLab pseudoseismic project is well under way. MatLab code has been written which imports spontaneous potential and gamma-ray logs and plots array logs whose amplitudes have been color coded to resemble seismic amplitude traces (pseudoseismic log arrays). These logs can be easily selected from a map-view window and then displayed as individual well-log or pseudoseismic cross sections.

Modeling

Modeling of thermal and burial histories in the Michigan Basin is proceeding. A finite-difference solution to the one-dimensional heat-conduction equation is being debugged. This program will produce the thermal histories consisting of burial vs. time, temperature vs. time, Time Temperature Indices, vitrinite reflectance data, and the maturation index of types I, II, and III kerogens. Data from several wells have been formatted for use in the program.

Technology Transfer

Internet Home Page

The Dundee Project internet home pages for Michigan Tech and Western Michigan University (WMU) can be reached at http://www.geo.mtu.edu/svl/michproj/ and http://www.wmich.edu/geology/corelab/coreres.htm.

Both Michigan Tech and WMU have set up servers for the Michigan DOE Project as a file transfer protocol site. At present, they contain zipped files that include all Autocad maps generated by the project as well as Excel spreadsheet files containing production information and other data. The Western Michigan address is ftp://141.218.61.24. The Michigan Tech address is the same as that for the internet home page.

Professional Papers and Presentations

A poster titled "Subsurface Databases: Graphical Display and Error Detection for Stratigraphic Interpretation in the Michigan Basin" was presented at the 1996 Geological Society of America annual meeting in Denver, Colo., on October 28. The poster included the graphical display of information derived from the FORTRAN lithology extraction program (LithLog) written previously. The poster included sections on the use of this type of lithology display for detecting errors in the database as well as its usefulness in correlating sequences in the basin. Further, the lithology log display was combined with more conventional logs (e.g., gamma-ray and neutron-density), which resulted in a vivid graphical display that would prove quite useful as a tool to facilitate the recognition of conventional log responses to different lithologies.

Workshop

A workshop was held at the Michigan Oil and Gas Association's monthly meeting on Oct. 17, 1996, to present the results of this Class 2 Reservoir Project to the Michigan independent oil and gas community. Oral presentations were made, and two different poster displays were presented. The core from the TOW No. 1-3 well, which has been preserved in wooden boxes, was brought from MTU and put on display. More than 40 representatives of the Michigan independent petroleum industry attended. A handout that contained a project overview and information on Crystal field was distributed. Notebooks containing field maps, production history data, and well statistics were on display and were examined closely by many of the independents.

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:
Dennis Sullivan
Don Clarke
Scott Walker
Chris Phillips
John Nguyen
Dan Moos
Kwasi Tagbor

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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. This project will involve the study of methods to identify sands with high remaining oil saturation and to recomplete existing wells with the use of advanced completion technology.

A deterministic three-dimensional (3-D) geologic model will be developed and state-of-the-art reservoir management computer software will be used to identify sands with high remaining oil saturation. The wells identified by the geologic and reservoir engineering work 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.

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.

Summary of Technical Progress

Reservoir Characterization

The laboratory system was modified to allow static Young's modulus measurements, which will be compared with dynamic measures of shear modulus. Core-plug samples from well No. 169-W were subjected to axial stress relaxation tests. These results will be compared with the reference data set built with Ottawa sand samples. Work also continued on a 3-D viscoelastic constitutive relationship for the static deformation experiments on the sands to model 3-D stress perturbations. This will quantify the elastic properties and viscosity of the samples under either test while taking into account the actual shape of the samples.

The rock–log model was studied with the help of Lawrence Livermore National Laboratory. The effects of three-phase (sand/clay/fluid) systems on the Gassmann relationship was found to be not entirely correct. The size of the error and its importance are being determined.

Reservoir Engineering

Production, injection, cumulative production, and cumulative injection bubble maps are being created in order to find potential bypassed oil. Efforts are concentrated in the upper and lower Terminal zones of fault block IV.

Deterministic 3-D Geologic Modeling

The deterministic 3-D geologic model continues to be updated and refined. The model area was expanded so that the horizon surfaces on the east side of the Daisy Avenue fault could be more accurately represented.

The geologic 3-D model uncovered a flawed interpretation west of the Daisy Avenue fault. An en echelon fault is the newer interpretation and is supported by the distribution of the scattered data of the four modeled horizons. The en echelon fault interpretation is structurally consistent with other parts of the Wilmington oil field. The fault interpretation is included in the model and provides good consistency for all the modeled layers. A recompletion candidate has been selected to test this interpretation and will be recompleted in the next budget period.

The deterministic geologic 3-D model for the upper Terminal zone of fault block IV prospect continues to be updated and refined. The 3-D model suggests that there is a structural trap for oil against the Harbor Entrance fault that can be exploited by the Y-63 recompletion candidate.

Pulsed Acoustic Logging

Log data from recompletion candidate wells Z-223 and Z-27 were further analyzed for useable acoustic data. Only a few short intervals were found to be useful. Researchers logged both wells with a nuclear device for comparative purposes and found reasonable agreement between acoustically derived and nuclear-derived results.

Researchers found in modeling wave propagation in cased wells that good cement/casing bond can actually *degrade* low-frequency waveforms in certain situations. Trapped energy is propagated more efficiently when cement/casing thickness is large and the formation is soft. This effect was exhibited in Wilmington field logging runs where the old logging tool yielded better results because of its lack of energy output below 1 kHz. The modified newer logging tool has a very energetic low-frequency energy band around 600 Hz. This was the tool used in logging the most recent recompletion candidates. Magnetic Pulse, Inc., is modifying its source and receiver arrangement of the acoustic tool again to eliminate this situation.

Recompletions

Recompletion candidate wells J-120 and J-15 have been successfully extreme overbalanced perforated, steam consolidated, and placed on production. Neither well has made a trace of sand.

Well J-120, the fault block V upper Terminal zone recompletion candidate, was perforated across the "Hx_o" sand. This well took 2,989 m^3 cold water equivalent (CWE) (18,800 bbl CWE) of steam injection. J-120 was shut in for soaking in late August and was returned to production in October. Oil production peaked at 37.7 m^3/d net (237 bbl/d net) with only a 32.3% water cut in early December (Fig. 1). As of the end of this reporting period, well J-120 was producing 55.5 m^3/d gross (350 bbl/d gross), 19.7 m^3/d net (124 bbl/d net), at a 64.5% water cut. The average producer in the upper Terminal zone reservoir produces only 3.9 m^3/d net (25 bbl/d net) with a very high 97.4% water cut. A tremendously encouraging sign is that the production temperature is almost back to presteam temperature. It was anticipated that, when the well cooled off after producing back the injected heat, the oil production might fall off quickly. This has not been the case. Gross and net productivities are much higher than the "optimized" waterflood recompletion. With the 3-D geologic model as a tool, the project is recompleting other candidate wells and further developing the "Hx_o" reservoir.

Well J-15, the fault block V Tar zone recompletion candidate, was perforated across the "F_1" and "F_0" sands. This well took 14,754 m^3 CWE (92,800 bbl CWE) of steam injection. J-15 was shut in for soaking in late August and was returned to production in late October. Oil production is steady at 16.1 m^3/d net (101 bbl/d net) with only a 79.9% water cut in late December (Fig. 2). This compares very favorably with the "optimized" recompletion done on well A-173. Well A-173 was completed in the same sands as J-15 and currently produces 3.5 m^3/d net (22 bbl/d net) with an 82.8% water cut. Production well Z1-7 was also completed in the same sands as wells J-15 and A-173 but with older recompletion techniques. Well Z1-7 produces 1.6 m^3/d net (10 bbl/d net) with an 87.5% water cut, much lower than well J-15 and slightly lower than well A-173.

As the result of the extremely successful results from wells J-120 and J-15, Tidelands Oil is completing all future wells in a similar manner whenever possible. Recompletion candidate wells Z-223 and Y-63 have been recompleted with the "optimized" waterflood recompletion techniques and placed on production.

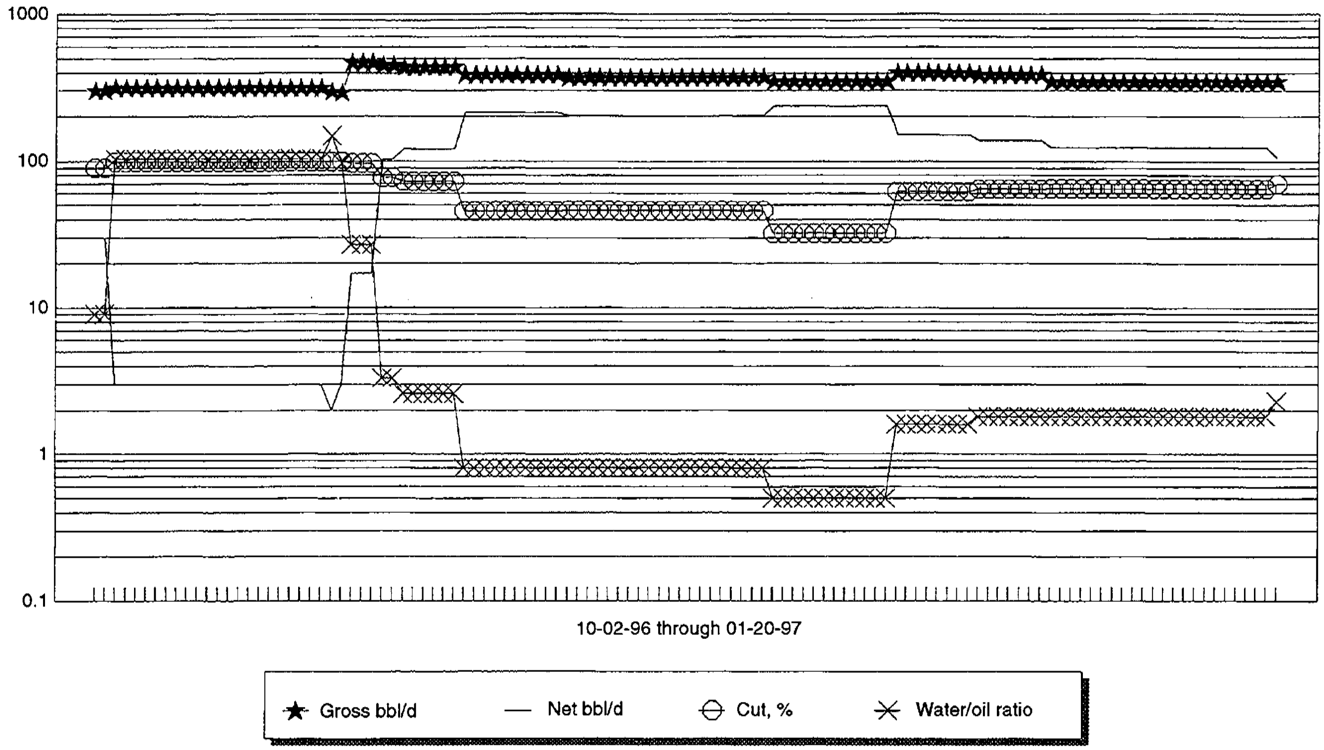

Fig. 1 Well J-120 recompletion.

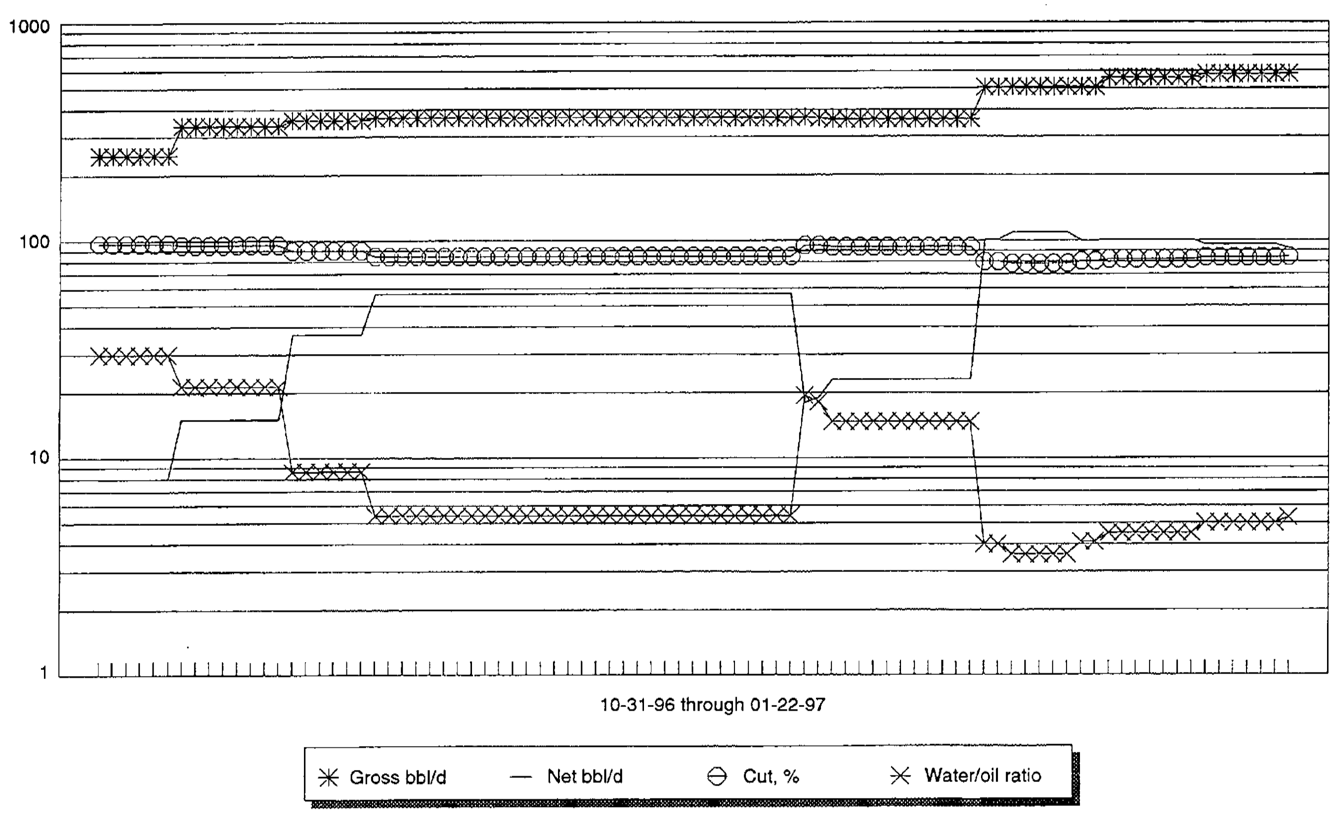

Fig. 2 Well J-15 recompletion.

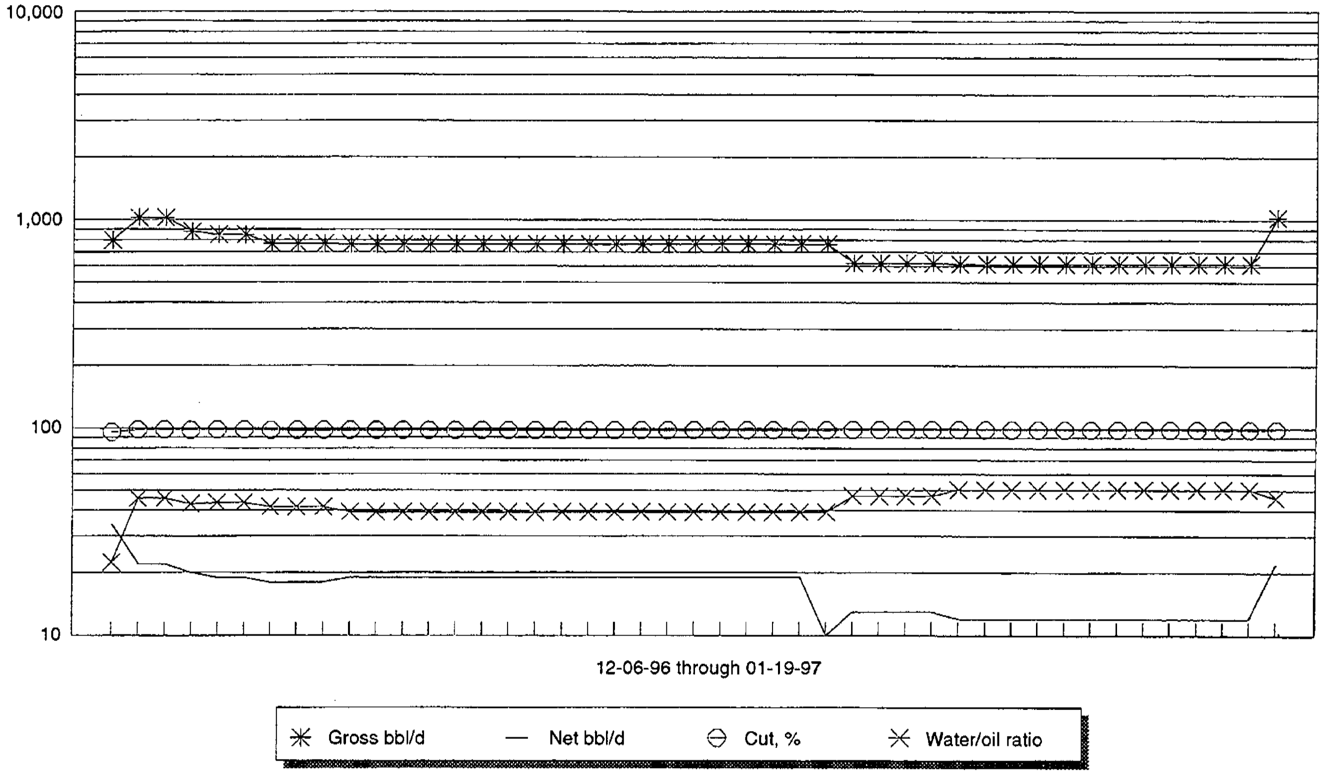

Fig. 3 Well Z-223 recompletion.

Well Z-223, the fault block V upper Terminal zone recompletion candidate, was conventionally perforated across the "Hx," "J," "Z," and "W" sands. The well was placed on production in December (Fig. 3), but it appeared to be damaged despite the "optimized" recompletion. Well Z-223 was acid stimulated and returned to production. Additional production results will be available in January 1997.

Well Y-63, the fault block IV upper Terminal zone recompletion candidate, was conventionally perforated across the "Hx," "J," "Y," and "K" sands. The well was placed on production in December (Fig. 4). Production results are lower than estimated, but the well may be cleaning up. If results are disappointing, this well also will be acidized.

Technology Transfer

Researchers attended the Society of Professional Well Log Analysts Symposium on "Petrophysics in 3-D" in Taos, New Mexico, in October.

Amoco visited Stanford University and discussed a collaborative effort on analyzing dipole data.

A paper titled "Anelasticity and Dispersion in Unconsolidated Sands" was presented at the 1996 American Geophysical Union meeting.

Papers were presented at the November 1996 Society of Exploration Geophysics annual meeting in Denver, Colo. Also at the meeting a workshop on problems associated with data aquisition of dipole and monopole data at Wilmington was held in conjunction with the Shear-Wave Special Interest Group of the Log Characterization Consortium.

Three presentations were made in November 1996 on the Waterflood Project Status to Petroleum Technology Transfer Council meetings held in Bakersfield, Ventura, and Long Beach, Calif. Also, a "point–counterpoint" discussion on oil detection behind pipe was hosted.

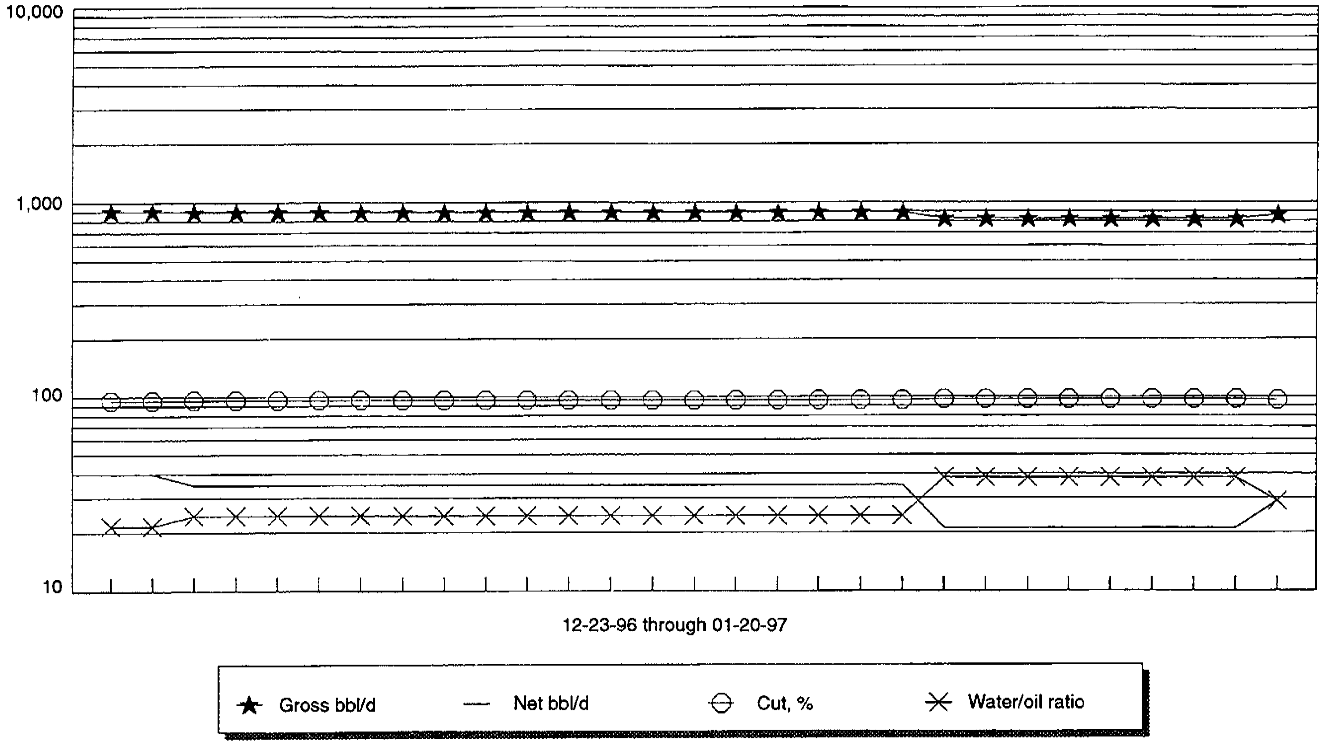

Fig. 4 Well Y-63 recompletion.

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

Contract No. DE-FC22-93BC14987

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
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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

Work this quarter has been concentrated on reservoir simulation and technology transfer.

Reservoir Characterization

The geologic reservoir characterization for the Schaben field is complete and has been presented at several national and regional meetings. Much of the geologic and production data, including maps, cross sections, and core analyses, are available online at the reservoir, lease, and well levels. The uniform resource locator (URL) to access the data is **http://www.kgs.ukans.edu/DPA/Schaben/schabenMain.html**.

A reservoir simulation study for the Schaben field is nearly complete. Production history for 34 years was matched at the field level, and small adjustments at the well level are under way. A Silicon Graphics workstation with the Western Atlas VIP Executive simulation software and a personal computer with the Department of Energy's (DOE) BOAST 3 are being used to perform this study. Both packages are conventional black oil simulators equipped with a graphics interface. The simulation models are being used to investigate and predict different enhanced oil recovery processes in an effort to optimize oil recovery.

When the reservoir simulation is complete, the results can be evaluated, reservoir management techniques can be developed, and the potential for deepening and recompletion of existing wells and targeted infill drilling can be evaluated.

Technology Transfer

A paper on the pseudoseismic approach as demonstrated at Schaben field was presented at the 1996 Gulf Coast Society of Economic Paleontologists and Mineralogists (SEPM) conference.[1] A presentation was given at the San Joaquin Geological Society (Bakersfield, Calif., December 10, 1996) on the application of pseudoseismics and PfEFFER to reservoir description. Presentations are scheduled for the Annual Meeting of the American Association of Petroleum Geologists (Dallas, Tex., April 6–9, 1997) and the Tertiary Oil Recovery Conference (Wichita, Kans., March 19–20, 1997).

Work with Kansas operators on the application of the technologies developed as part of the Class II project will continue. Access to the digital data and results from the project are provided through an online (Internet) accessible format.

Reference

1. J. F. Hopkins, T. R. Carr, and H. R. Feldman, Pseudoseismic Transforms of Wireline Logs: A Seismic Approach to Petrophysical Sequence Stratigraphy, in *Stratigraphic Analysis Utilizing Advanced Geophysical, Wireline and Borehole Technology for Petroleum Exploration and Production,* J. A. Pacht, R. E. Sheriff, and B. F. Perkins (Eds.), Gulf Coast Society of Economic Paleontologists and Mineralogists 17th Annual Research Conference, Houston, Tex., December 8–11, 1996.

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-FC22-94BC14991

Phillips Petroleum Company
Odessa, Tex.

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

Principal Investigator:
Kimberly B. Dollens

Project Manager:
Jerry Casteel
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 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) located in 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.

Summary of Technical Progress

Well Work Activities

During this quarter, two wells were drilled within the SCU project area. The first, well No. 7-13, was drilled as a replacement well for production well No. 7-06, which was previously plugged and abandoned. The second, well No. 7-15, was drilled as a new take-point on the northern tract line of Tract 7.

	After			
Well	BOPD	BWPD	MCFPD	
SCU No. 7-13	23	87	0	Oct. 21, 1996
SCU No. 7-15	25	178	2	Oct. 18, 1996

Note: BOPD, barrels of oil per day; BWPD, barrels of water per day; MCFPD, thousand cubic feet per day.

Three wells were converted to water injection during this quarter.

	Before			After
Well	BOPD	BWPD	MCFPD	
SCU No. 5-02	12	735	3	Shut in pending injection line tie-in
SCU No. 5-08	6	60	3	Injecting @ 250 BWPD and 560 psig (November 1996)
SCU No. 8-18	6	176	1	Injecting @ 518 BWPD and 750 psig (November 1996)

Four temporarily abandoned wells were reactivated during this quarter.

Well	BOPD	BWPD	MCFPD	
SCU No. 6-20	11	75	4	Oct. 19, 1996
SCU No. 7-02	5	119	0	Sept. 30, 1996
SCU No. 7-05	5	220	1	Oct. 8, 1996
SCU No. 7-10	Shut in pending flow line tie-in			

Five wells were checked for fill and acidized during this quarter.

	Before			After			
Well	BOPD	BWPD	MCFPD	BOPD	BWPD	MCFPD	
SCU No. 2-08	6	90	1	13	128	1	Dec. 12, 1996
SCU No. 2-21	5	40	1	6	98	3	Nov. 10, 1996
SCU No. 2-24	7	38	1	9	63	2	Nov. 20, 1996
SCU No. 6-06	3	40	1	3	148	1	Dec. 12, 1996
SCU No. 8-02	10	59	1	8	81	0	Dec. 4, 1996

No tertiary response is anticipated until mid-1997; however, production is being monitored for CO_2 content in the produced gas stream. CO_2 production commenced during the fall of 1996 in well Nos. 7-05, 6-22, 6-24 (RC-3), 6-03, and 6-07. The compression–recycle facilities were started up in December 1996 with the recycle gas being injected primarily in well No. 2-26W.

The total volumes injected in all four injection wells for this quarter were:

	Gas injection, MCF		
	October 1996	November 1996	December 1996
Monthly	242,743	269,465	276,626
Daily average	7,830	8,982	8,923
Cumulative	576,066	845,531	1,122,157

Technology Transfer

A talk[1] was presented and a researcher participated in a panel discussion on "Cost Optimization—Installation and Operations" at the 2nd Annual Permian Basin CO_2 Conference in December 1996. A paper on evaluation of injection profiling methods has been prepared for presentation at two symposia.[2–3] A paper on drilling and completing injection wells in the SCU has also been prepared for presentation at the second symposium.[4]

Development is continuing of an SCU Internet site for data and technology transfer. The prototype has been completed for intra-company use only, but editing is necessary prior to finalizing for the Internet.

References

1. K. B. Dollens, *Cost Optimization/Operations in WAG Flooding: E. Vacuum Grayburg and So. Cowden Units,* paper presented at the 2nd Annual Permian Basin CO_2 Conference, Midland, Tex., December 10–12, 1996.
2. K. B. Dollens, B. W. Wylie, J. C. Shoumaker, O. Johannessen, and P. Rice, *The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO_2 WAG Horizontal Injection Wells,* paper SPE 37470 prepared for presentation at the 1997 SPE Production Operations Symposium, Oklahoma City, Okla., March 9–11, 1997.
3. K. B. Dollens, B. W. Wylie, J. C. Shoumaker, O. Johannessen, and P. Rice, *The Evaluation of Two Different Methods of Obtaining Injection Profiles in CO_2 WAG Horizontal Injection Wells,* paper prepared for presentation at the Phillips Petroleum Company Exploration and Production Technical Symposium, Bartlesville, Okla., April 2–4, 1997.
4. J. C. Shoumaker, *Drilling and Completions Considerations of Horizontal CO_2 Injection Wells—South Cowden Unit,* paper prepared for presentation at the Phillips Petroleum Company Exploration and Production Technical Symposium, Bartlesville, Okla., April 2–4, 1997.

PREPARATION OF NORTHERN MID-CONTINENT PETROLEUM ATLAS

Contract No. DE-FG22-96BC14844

University of Kansas
Lawrence, Kans.

Contract Date: Aug. 30, 1996
Anticipated Completion: Aug. 31, 1997
Government Award: $250,000
(Current year)

Principal Investigator:
Lee C. Gerhard

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 31, 1996

Objectives

The objectives of the second-year program will be to continue and expand upon the Kansas elements of the original program and provide improved online access to the prototype atlas. The second year of the program will result in a prototype digital atlas sufficient to demonstrate the approach and to provide a permanent improvement in data access to Kansas operators. The ultimate goal of providing an interactive history-matching interface with a regional database remains for future development as the program covers more geographic territory and the database expands. The long-term goal is to expand beyond the prototype atlas to include significant reservoirs representing the major plays in Kansas, Nebraska, South Dakota, North Dakota, the Williston Basin portion of Montana, and the Denver–Julesburg Basin of eastern Colorado and southeastern Colorado.

Primary products of the second-year prototype atlas will be online accessible digital databases covering two additional petroleum plays in Kansas. Regional databases will be supplemented with geological field studies of selected fields in each play. Digital imagery, digital mapping, relational data queries, and geographical information systems will be integral to the field studies and regional data sets. Data sets will have relational links to provide opportunity for history-matching, feasibility, and risk-analysis tests on contemplated exploration and development projects. The flexible web-like design of the atlas provides ready access to data and technology at a variety of scales from regional to field, to lease, and finally to the individual well bore. The digital structure of the atlas permits the operator to access comprehensive reservoir data and customize the interpretative products (e.g., maps and cross sections) to his/her needs. The atlas will be accessible in digital form on line with the use of a World Wide Web browser as the graphical user interface.

Regional data sets and field studies will be free-standing entities that will be made available on line through the Internet to users as they are completed. Technology transfer activities will be ongoing from the earliest part of this project, providing data information sets to operators before the full digital atlas compilation.

Summary of Technical Progress

As part of the first-year project, home pages and data schema for the atlas overview and field studies were developed and made accessible through the World Wide Web. The atlas structure includes access to geologic, geophysical, and production information at various levels. Several approaches have been developed that provide efficient and flexible screening and search procedures. The prototype of the digital atlas is accessible through the Kansas Geological Survey Petroleum Research Section (PRS) home page [the universal research locator (URL) is **http://www.kgs.ukans.edu/PRS/PRS.html**]. The Digital Petroleum Atlas (DPA) home page is available directly at **http://www.kgs.ukans.edu/DPA/dpaHome.html**.

The multi-pay Terry field in Finney County (Fig. 1) was selected for inclusion in the DPA. Terry field was a 1991 discovery with primary producing zones in the Lansing–Kansas City, Marmaton, and Mississippian. A number of county-scale geologic maps are being generated and will be loaded into the DPA. Well log and other well information for Terry field are being collected, and a field study is under way.

Online Prototype

The following changes and additions have been made to the online prototype atlas.

DPA Home Page: http://www.kgs.ukans.edu/DPA/dpaHome.html

On the DPA home page, a new set of navigation buttons for the national, Northern Mid-continent, and Kansas levels of the DPA provides clear separation for efforts in the different areas. Most efforts are placed in Kansas, but significant information will be added to the other areas. A report on electronic publication in the earth sciences that will be published in *Computers and Geosciences* is available through a link to the DPA home page.

Kansas Home Page: http://www.kgs.ukans.edu/DPA/dpaKansas.html

Residual Bouguer gravity and reduced-to-the-pole magnetic data and maps of Kansas are available through the Kansas regional geologic setting home page (**http://www.kgs.ukans.edu/DPA/regional.html**). Small-scale maps with selected overlays can be viewed on line, or larger

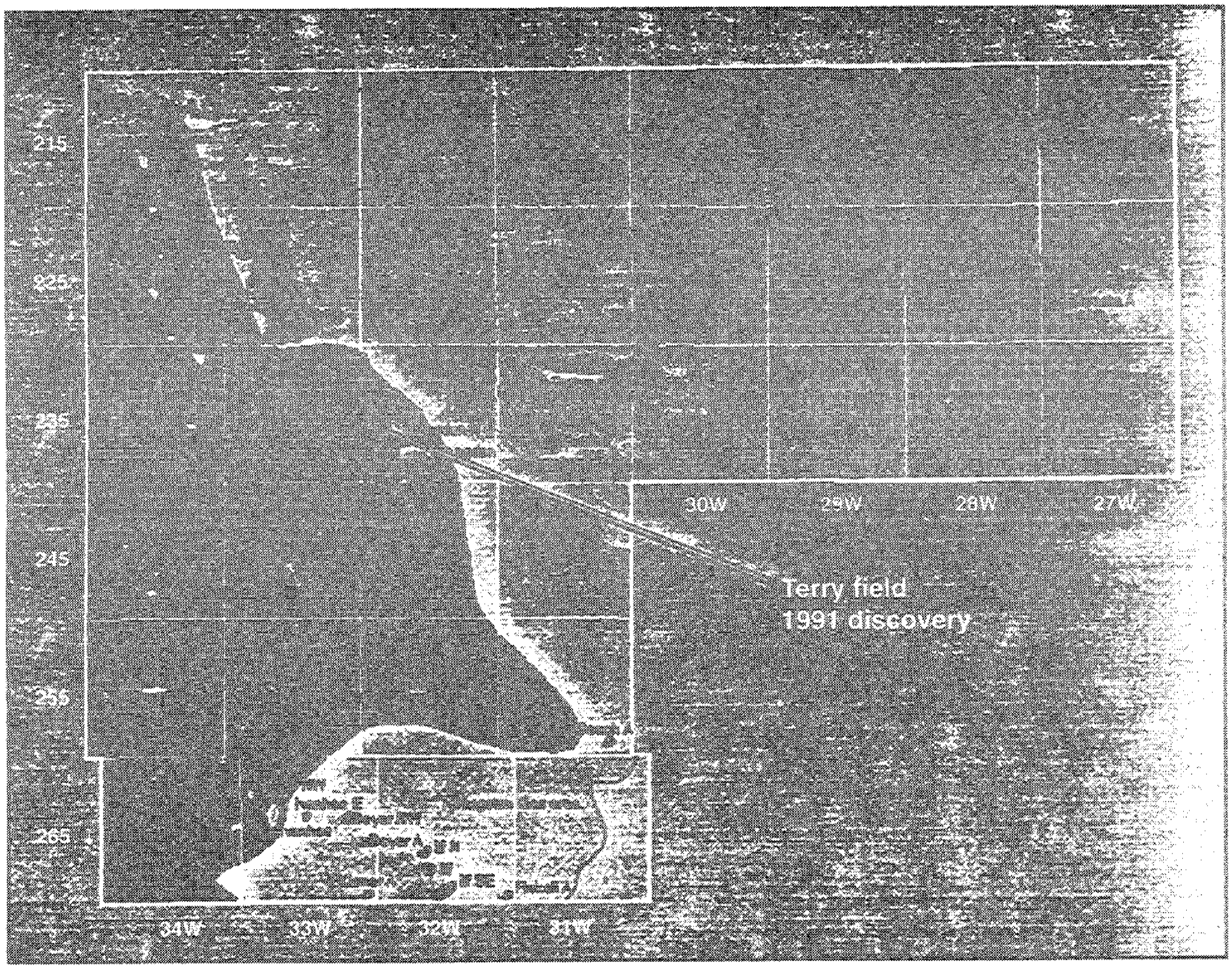

Fig. 1 Location of Terry field in Finney County, selected for inclusion in the Digital Petroleum Atlas.

scale maps can be downloaded. Overlays include county lines, outlines of oil and gas fields, Post-Mississippian structure, and Precambrian structure. A general discussion of the gravity and magnetic data is provided.

Field Pages: Various URLs

Additional information was added to the Arroyo, Big Bow, Gentzler, and Schaben field pages. Production data at the field and lease level are being updated through 1996.

Technology Transfer

Technology transfer activities include presentations at national and regional meetings and provision of monthly electronic updates and online availability of the DPA products. Project information and progress reports are linked to the DPA home page. The prototype DPA remains one of the most visited pages on the Kansas Geological Survey web site. Current usage statistics can be accessed at the bottom of the Petroleum Research Section home page or at **http://www.kgs.ukans.edu/PRS/usage/past_stats.html**.

Presentations were given at the Annual Meeting of the Geological Society of America (Denver, Colo., October 28–31, 1996) and at the Interstate Oil and Gas Compact Commission Annual Meeting (Las Vegas, Nev., December 8–10, 1996). Another presentation is scheduled at the meeting of the Powder River Basin Section, Society of Petroleum Engineers (SPE) Rocky Mountain Region, on May 13, 1997. An abstract of a paper for presentation at the 72nd Annual Meeting of the SPE (San Antonio, Tex., October 5–8, 1997) has been submitted. Papers citing the DPA as an example of new forms of online publication are in press for *Computers and Geosciences* and in the *Proceedings of the Geoscience Information Society*.

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

Contract No. DE-FC22-93BC14960

Texaco Exploration and Production, Inc.
Midland, Tex.

Contract Date: June 1, 1993
Anticipated Completion: Dec. 31, 1997
Government Award: $523,000
(Current year)

Principal Investigator:
Sami Bou-Mikael

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 31, 1996

Objectives

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 for this quarter included:

- Monitor reservoir performance.
- Evaluate the feasibility of three workovers in wells Kuhn No. 14, Stark No. 8, and Kuhn No. 38.

Summary of Technical Progress

Production decline in the Port Neches project is stabilizing at 60 bbl of oil per day from two wells: Kuhn No. 14 and No. 38 wells. The project is approaching the economic limit and will be evaluated for conclusion. The carbon dioxide (CO_2)-recycled volume is dropping below 2 million cubic feet per day, which enables only one compressor to remain active.

Water injection in the project has currently been discontinued because of low injectivity that caused high back pressure at the wells, which eventually caused mechanical problems at the pump. CO_2 injection, however, is continuing in Kuhn No. 42 well and Stark No. 10 well. Freezing problems occurred in December 1996 that forced shutin of all CO_2 operations for nearly 2 weeks. Kuhn No 15R well has been evaluated for a workover; it was determined that it is mechanically risky because of corrosion of the tubing and casing strings. The remaining oil in the vicinity of this well is minimal according to reservoir simulation and the high gas/oil ratio production history of the well. Texaco Exploration and Production, Inc. will continue to produce the wells until the decision is made regarding project continuation.

Field Operations

Table 1 lists the most recent tests during the month of December 1996 for the producing and injection wells. Figure 1 shows the monthly production of oil.

Technology Transfer

The results of this investigation are summarized in a paper presented at the 10th Society of Petroleum Engineers/U.S. Department of Energy Improved Oil Recovery Symposium held in Tulsa, Okla., April 21–24, 1996.[1]

TABLE 1

Well Test Results, December 1996*

Well No.	BOPD	MCFGD	Basic sediment and water, %	Pressure, psi	Choke
		Producing wells			
Kuhn No. 14	35		97	470	34
Kuhn No. 38	34		95	450	10
		Injection wells			
Kuhn No. 42		1270		1043	
Stark No. 10		619		1045	

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

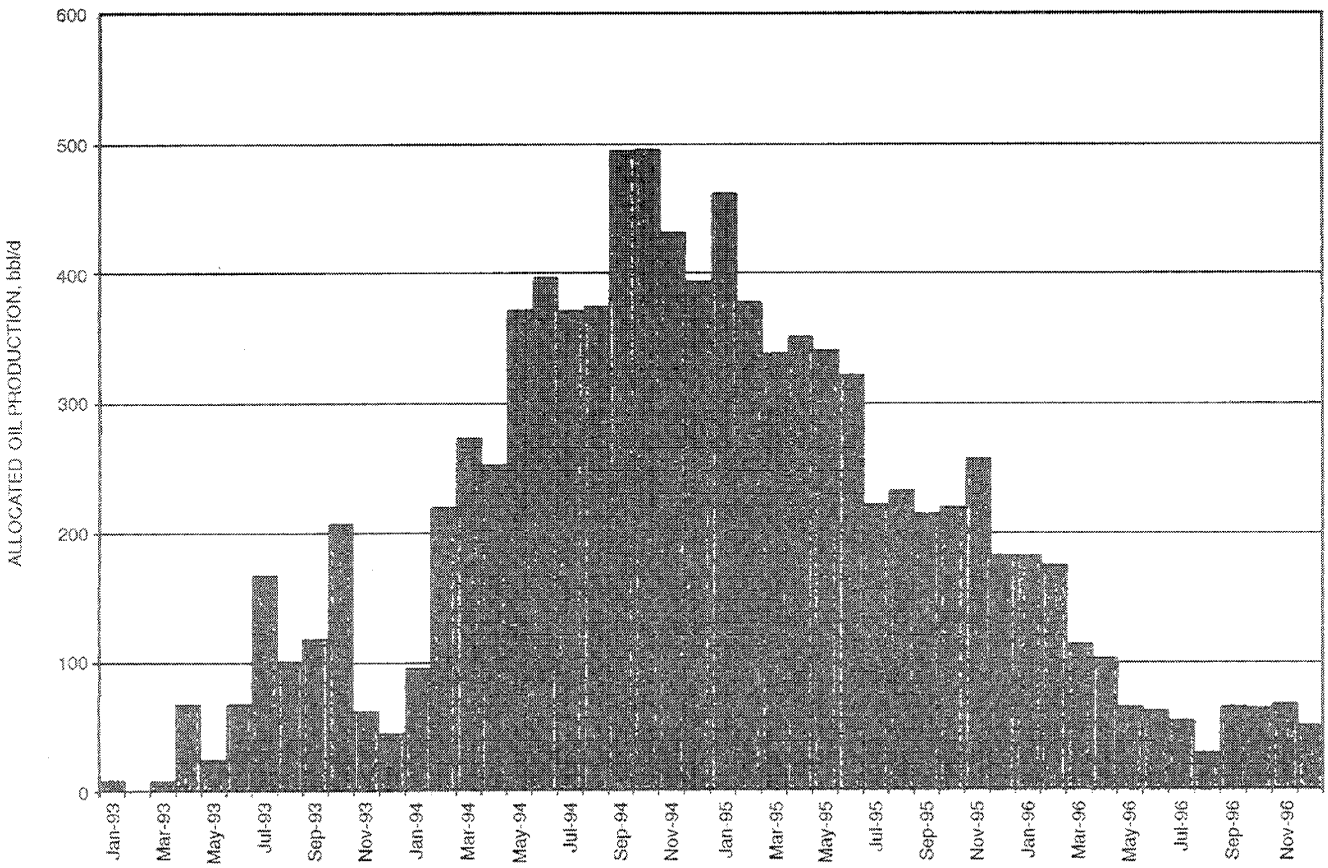

Fig. 1 Port Neches CO_2 project allocated oil production.

Reference

1. D. Diaz, Z. Bassiouni, W. Kimbrell, and J. Wolcott, *Screening Criteria for Application of Carbon Dioxide Miscible Displacement in Water-flooded Reservoirs Containing Light Oil,* paper SPE 35431 presented at the 10th Society of Petroleum Engineers/U.S. Department of Energy Improved Oil Recovery Symposium, Tulsa, Okla., April 21–24, 1996.

AN INTEGRATED STUDY OF THE GRAYBURG/SAN ANDRES RESERVOIR, FOSTER AND SOUTH COWDEN FIELDS, ECTOR COUNTY, TEXAS

Contract No. DE-FC22-93BC14982

Laguna Petroleum Corporation
Midland, Tex.

Contract Date: Aug. 2, 1994
Anticipated Completion: Feb. 2, 1998
Government Award: $649,100
(Current year)

Principal Investigators:
Robert C. Trentham
Richard Weinbrandt
William Robertson

Project Manager:
Chandra M. Nautiyal
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 31, 1996

Objective

The principal objective of this study is to demonstrate in the field that three-dimensional (3-D) seismic data can be used to help identify porosity zones, permeability barriers, and thief zones and thereby improve waterflood design. Geologic and engineering data will be integrated with the geophysical data to result in a detailed reservoir characterization. Reservoir simulation will then be used to determine infill drilling potential and the optimum waterflood design for the project area. This design will be implemented and the success of the waterflood evaluated.

Summary of Technical Progress

Seismic work concerned seismic recognition of Grayburg carbonate porosity and development of maps of the distribution of seismic properties that can be related to reservoir porosity. Synthetic seismograms representing various porosity combinations for the Grayburg A sequence were interpolated in forward models to demonstrate waveform character, and a seismic inversion model was used as the basis for work with seismic-guided attribute maps, which have been instrumental in defining porosity within the upper Grayburg.

Synthetic models of variations of porosity in the Grayburg A1 and A2 zones show that porosity may be expected to cause reflection changes prominent enough to be noticed. Recognizing porosity in actual seismic data would be subjective because of weak criteria, and mapping suspected changes would be inaccurate. The complication of interpretation is caused by the presence of the seismic wavelet, which has inherent problems of distortion caused by compound reflection interference related to bandwidth limitation (resolution). The seismic trace does not adequately resemble a well log for the purpose of displaying fine rock qualities, nor does it have the ability to accurately resolve important lithologic boundaries. Analyses of specific zones of rock sequence are inherently wrong where the zone boundaries are picked from these compound reflections, as demonstrated with previously made forward-synthetic models.

Removing the wavelet from the stratigraphic analysis in this project is of primary interest, and it has been accomplished by calculating a constrained inversion model of the 3-D seismic data volume. Horizons tracked from amplitude trace data were revised using the inversion model boundaries in order to accurately isolate zones for analysis.

Geology

The geologic work included integration of the geologic model into 3-D to accurately portray the lithologic markers, coring and logging of the Witcher No. 12 well, and working toward the development of a successful completion technique for the lower Grayburg and San Andres. Considerable effort went into developing a usable seismic velocity–log porosity transform.

Engineering

Engineering work included development of a successful completion technique for the lower Grayburg and San Andres, which would contact the maximum volume of reservoir, minimize potential water production, and be cost effective. The Witcher No. 12 well was drilled, and Foster-Pegues No. 4 well was re-entered and converted to injection. The first steps in the quantitative integration of seismic data into the reservoir simulation were taken. Work on water quality, buildup, and fall-off tests and the update of production and injection data in the model continued.

Technology Transfer

A paper titled "The Use of Core and Core Analysis in an Integrated Study of the Grayburg/San Andres Reservoir, Foster Field, Ector County, Texas" was presented at the West Texas Geological Society 1996 Fall Symposium on Permian Basin Oil and Gas Fields: Keys to Success That Unlock Future Reserves, on October 31 and November 1, 1996.

A paper titled "An Integrated Study of the Foster (Grayburg/San Andres) Field, Ector County, Texas" was submitted for presentation at the Southwestern Petroleum Short Course, Lubbock, Tex., to be held April 2–3, 1997.

APPLICATION OF RESERVOIR CHARACTERIZATION AND ADVANCED TECHNOLOGY TO IMPROVE RECOVERY AND ECONOMICS IN A LOWER QUALITY SHALLOW SHELF CARBONATE RESERVOIR

Contract No. DE-FC22-94BC14990

Oxy USA, Inc.
Midland, Tex.

Contract Date: Aug. 3, 1994
Anticipated Completion: June 14, 1996
Government Award: $2,023,000
(Current year)

Principal Investigator:
Archie R. Taylor

Project Manager:
Chandra Nautiyal
National Petroleum Technology Office

Reporting Period: Oct. 1–Dec. 31, 1996

Objective

This project will demonstrate in the field how innovative technologies such as cross-wellbore tomography, hydraulic fracture orientation detection, three-dimensional (3-D) seismic methods, and cycle CO_2 stimulation can improve the economics of conventional CO_2 flooding.

Summary of Technical Progress

During this quarter simulation performance forecasts were made with the use of the base geologic model. The surface seismic and wellbore data were combined to develop an improved geologic model for the simulator. Efforts to integrate the wellbore seismic results into the reservoir characterization continue. Problems with the wellbore seismic processing were traced to the processing software, which is being corrected.

3-D Seismic Integration

The second stage of the geologic modeling required the integration of the 3-D seismic data and the well data to capture the interwell porosity variations portrayed by the seismic interpretations.

A methodology was developed to convert seismic attributes to log properties of porosity and thickness × porosity (pore volume) within the San Andres reservoir beneath the U.S. Department of Energy (DOE) demonstration area.[1] The vertical resolution of the 3-D seismic within the San Andres reservoir was approximately 30 ft, which allowed identification of the two major depositional parasequences within the main pay—M1 to M3 and M3 to M5 (Fig. 1). Hence it was possible to develop a seismic-derived map of porosity and thickness × porosity for both intervals that represents the two-dimensional (x-y) distribution of the values averaged over the vertical interval. The basic reservoir model represents the M1–M3 interval with three layers and the M3–M5 interval with four layers. Therefore the 3-D seismic vertical resolution is inadequate to describe the model layering.

A methodology was developed to subdivide the seismic intervals to match the model layering. At each wellbore control point, the model layers' percentages of the total thickness and thickness × porosity were determined for both the M1–M3 and M3–M5 intervals. Percentage maps were constructed from this information, which were then integrated with the seismic maps to produce thickness and thickness × porosity maps for each of the seven model layers between the M1 and M5 markers. This approach appears to be superior to using a single proportioning factor. The thickness and thickness × porosity maps were integrated to obtain a porosity distribution map for each layer. A porosity vs. permeability transform was developed from wellbore data for each layer, which allowed the construction of a permeability distribution map. For the layers above and below the seismic intervals, well data alone provided the model input. The impact of these layers on oil recovery is much less than those within the seismic intervals.

The result incorporates the wellbore data and the geophysical data for all nine layers and provides average porosity, average permeability, thickness, and structure for model grids. Several passes were made to maximize the efficiency of the computer gridding to represent the variability of the reservoir parameters. The dimensions of the 3-D seismic bins (110 ft × 82.5 ft) are such that at least one control point is

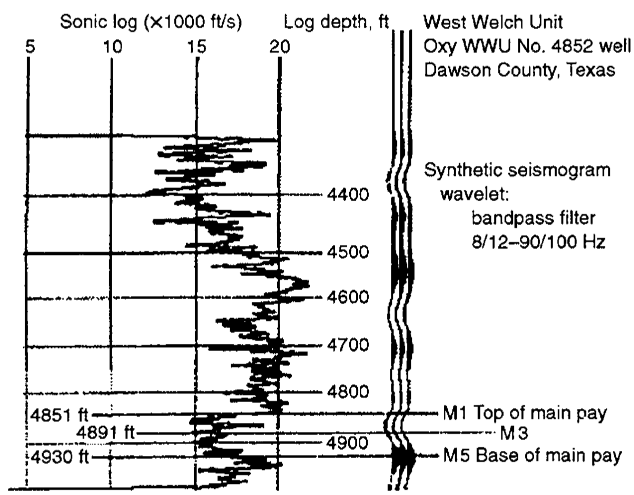

Fig. 1 Comparison of acoustic log and seismic trace for a typical well.

available for each model grid cell. These layers will be sampled to the simulation grid for history matching to test the approach.

Tomography

The wellbore seismic processing continues to be refined. Changes were made to the processing software that should put the reflections and calculated velocities at the correct depths to improve the correlation of seismic and wellbore data.

Numerical Simulation

A radial model was set up to simulate the water-alternating-gas (WAG) injection test run in the 4816w injection well. The objective was to obtain a history match of the field test by adjusting the relative-permeability hystereses curves. The model pore volume was set large enough so that the 2-week test would not raise the average pressure significantly. Alternating 3-d injection periods of CO_2 followed by water then CO_2 again were run, and the relative permeability was adjusted until the bottomhole injection pressures measured during actual injection were matched. The resulting relative-permeability hystereses curves were input into the full area model to simulate the WAG cycles to be evaluated. The exact curves from the radial model were impossible to use, and the new hystereses curves had to be adjusted closer to the original curves for the full model to run to completion.

The simulator used the new hystereses curves to predict the performance of several scenarios to determine an optimum operating plan for the project that would maximize the economics. A continuous CO_2 injection case was run to aid in designing the CO_2 distribution system. Figure 2 shows the forecasted production for three scenarios. The continuous case assumes continuous CO_2 injection for 3 yr before switching to a 1-month water then 1-month CO_2 WAG injection. The base case assumes 6 months of continuous CO_2 before changing to the 1:1 WAG injection. The fracture case is identical to the base case except that the eight injection wells in the south had high-permeability zones extended east and west for four grid blocks from the wellbore grid block to simulate a 400-ft fracture that appears achievable from the fracture optimization field testing. The result shows that the fracturing case improves CO_2 utilization, increases recovery, and accelerates production.

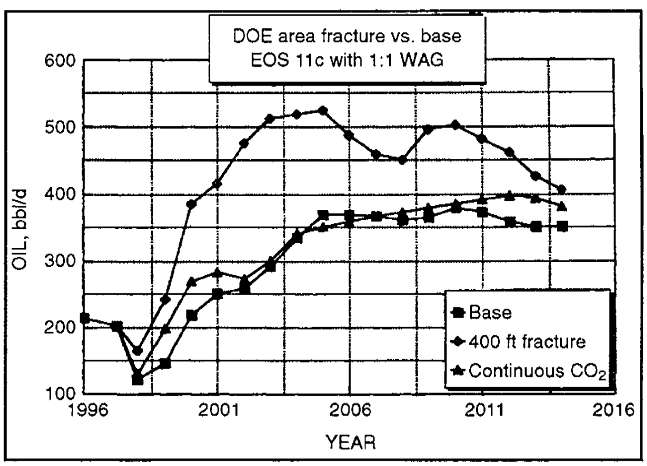

Fig. 2 Comparison of production for different operating cases.

Two equations of state were used in the simulation studies in an effort to match the slim-tube miscible performance. Work continues on improving the representativeness of the equations of state.

Project Area Preparation

Facilities design criteria are based on the simulator's forecasted production and injection rates. The facilities being designed include a tap into the Este CO_2 pipeline, the CO_2 distribution system, and the wellhead for the future injection of recycled gas. Also, the production and gas-gathering facilities are being upgraded to allow more detailed measurement of the produced fluids. The gas-gathering system will deliver the total produced gas stream to the Welch gas plant for (1) removal of the natural gas liquids (NGL), consisting of propane and heavier components; (2) compression; and (3) return of the CO_2 volume contaminated with residue gas for reinjection. The contaminated gas will have a higher miscibility pressure (about 1450 psi) than the original (1200 psi) for pure CO_2.

The revenue from NGL recovery should at least offset the compression and dehydration costs because the gas processing facility is already in place. Before the CO_2 flood, the NGL recovery was about 2 gal of NGL per barrel of oil produced. During the CO_2 flood, the NGL recovery is estimated to average 5.5 gal per barrel of oil produced. This value will vary depending on the initial oil composition but can be an important source of revenue if processing facilities are already available.

Economic Analysis

The simulation performance forecasts for the various operating scenarios were converted to cash-flow projections for evaluation purposes. This required estimation of development and operating costs and a forecast of future prices ($19.09 per bbl of oil and $13.39 per bbl of NGL escalated at 4% per annum from November 1, 1997). The project economics were maximized under the base scenario for the fracturing case with the use of the wwu10 equation of state. Under this scenario, an additional two million barrels of oil were recovered over a 14-yr period with a gross CO_2 utilization of 17.4 MCF/yr. The indicated gross (no DOE funding) project economics were a 13.8% annual rate of return and a 7.4-yr payout.

Technology Transfer

A presentation was made before the West Texas Geological Society,[2] and a poster session covering the conversion of seismic attributes to log properties was conducted.

References

1. G. P. Watts and G. D. Hinterlong, *Seismic Estimate of Porosity in the Permian San Andres Carbonate Reservoir, Welch Field, Dawson County, Texas,* paper presented at the Oklahoma Geological Survey Workshop on Platform Carbonates of the Southern Midcontinent, Oklahoma City, Okla., March 26–27, 1996.
2. A. Taylor and G. Hinterlong, *Use of Multiple Log Curves to Predict Permeability in a Dolomite Reservoir,* paper presented at the Fall Symposium of the West Texas Geological Society, Midland, Tex., October 30–31 and November 1, 1996.

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