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MICELLAR-POLYMER JOINT DEMONSTRATION PROJECT,
WILMINGTON FIELD, CALIFORNIA

MASTER

Third Annual Report
June 1978—July 1979

Work Performed for the Department of Energy
Under Contract No. DE-AC03-77ET12044

Date Published—August 1981

City of Long Beach
Long Beach, California

U. S. DEPARTMENT OF ENERGY

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WILMINGTON FIELD, CALIFORNIA

Third Annual Report
June 1978—July 1979

950 6242 ✓
Harrison L. Staub, *Principal Investigator*
Department of Oil Properties
City of Long Beach
P.O. Box 20050
Long Beach, California 90801

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Gary D. Peterson, *Technical Project Officer*
U.S. Department of Energy
Fossil Energy Division
1333 Broadway
Oakland, California 94612

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SUMMARY

The micellar-polymer demonstration project to be conducted--through the design phase--in the HXa sand of Wilmington Field is proceeding satisfactorily but has fallen behind schedule. The laboratory sample of the cosurfactant used to formulate the "final" design micellar-slug apparently was not representative of the plant product. The cosurfactant received from the manufacturer's plant was blended with the other components of the "final" design slug and core-flood tested. The results of these latter core floods were unsatisfactory. The recovery efficiencies were much lower than those achieved using the laboratory sample cosurfactant "final" design slug. Nearly six months of reformulating and additional core testing were required to finally achieve satisfactory laboratory results.

Other laboratory tests were performed to optimize the polymer buffer for size and concentration. Bids by different manufacturers to supply polymer for the field tests will be analyzed and the most cost-effective polymer will be selected.

After the slug problem had been resolved, project timing again slipped due to inability to obtain a commitment for a steady supply of the diesel fuel required for slug formulation.

All surface facilities have been installed. The project production and injection wells are completed and in operation. Mechanically, the system is completely ready to start micellar injection operations. However, other reservoir and reservoir fluid problems have been encountered in production and injection operations during the pre-flush period. These difficulties are being resolved.

INTRODUCTION

A contract was signed on July 7, 1976 by the City of Long Beach and the U. S. Department of Energy (formerly ERDA) to conduct jointly a Micellar-Polymer Project in Wilmington Field which would establish a tertiary oil recovery technique applicable to unconsolidated oil sands typical of the California Coastal Province. This project is an application of the Maraflood (TM) Process with technical assistance being provided by Marathon Oil Company.

Wilmington Field, the largest oil accumulation in California, is located on the southwestern margin of the Los Angeles Basin along the shoreline at Long Beach and extends inland at Wilmington. Figure 1 shows the location of Wilmington

Field in relation to other major oil accumulations in the basin. The Wilmington structure is an elongated anticline about eleven miles long by three miles wide and trends northwest to southeast. The structure is transected by a series of normal faults, as shown in Figure 2, which divide the seven major productive horizons into nine major fault blocks and many separate pools. The axial cross-section is shown in Figure 3.

Production is obtained primarily from 1800 to 2000 feet of unconsolidated sand beds ranging in age from late Miocene to early Pliocene. The shallow sands of the Tar, Ranger and Upper Terminal Zones are highly unconsolidated and are characterized by unusually high compressibility. The period of primary production was accompanied by a major surface subsidence problem, particularly along the vulnerable tidelands area. A peak subsidence of 29 feet was reached in 1960, adjacent to the turning basin of the major shipping channel and dock facilities just north of the Naval Shipyard. Full scale waterflood operations were initiated after pilot projects demonstrated that this method was not only the primary means for arresting subsidence, but was also economically viable as a secondary recovery method.

Oil production in Wilmington Field is currently about 128,000 barrels per day. The peak rate of 250,000 barrels per day occurred in 1969 following the major development of East Wilmington. The cumulative production as of April 1, 1979 was approximately 1.92 billion barrels. The current water injection rate is 1.32 million barrels per day and cumulative water injection is 6.9 billion barrels. It is estimated that the residual oil saturation for the average sand at economic limit after waterflood will be about 50 percent of the oil initially in place. Even assuming a low average porosity of 28 percent and average interstitial water saturation of 30 percent the total unrecovered oil after waterflooding will be 2-1/2 billion barrels in the upper three zones of the Wilmington Field. This vast pool of unrecovered oil represents a major challenge to develop a viable technique for tertiary oil recovery.

The area selected for the pilot project is located in the HX subzone of Fault Block V, which is bounded by the Allied and Daisy Avenue fault systems. This area is shown in Figure 4. The pilot project is located in a watered-out area of the HXa sand on the flank of the original peripheral waterflood, shown in Figure 5. The HXa Sand is the uppermost member of the HX Subzone of the Upper Terminal Zone in Fault Block V. This interval is shown in Figure 6. The HXa Sand is a relatively massive, uniform sand body with adequate permeability and net sand thickness. The reservoir characteristics of the HXa Sand are tabulated in Table I.

The twenty-year history of peripheral injection of low-temperature, high-sulfate water--the source of which was a shallow, saline groundwater supply--significantly reduced the reservoir temperature on the flanks. This peripheral injection created a north-to-south temperature gradient through the area selected for the project. The high sulfate content of the source water contaminated much of the reservoir with nutrients for sulfate-reducing bacteria which created a severe corrosion problem in the project producing wells. A period of preflush injection--authorized because of delay in initiating micellar injection--has mitigated two problems in the project area: (1) flushing the high-sulfate water ahead of the micellar slug and (2) normalizing the reservoir fluid temperatures and consequent fluid mobilities.

Laboratory studies have been performed by Marathon's Denver Research Center to determine the most efficient micellar slug for oil displacement and to determine the best polymer type and concentration for mobility control. These studies provided the information which established the optimum injection volumes.

A mini-injectivity test was performed in Well FT-1 in which an 850-barrel sulfonate slug was injected followed by several types of mobility buffer polymers at varying concentrations and volumes. This test was performed to demonstrate that a sulfonate system and various concentrations of polymers could be injected at acceptable rates and pressures.

Surface facilities for the project have been installed, portions of which were utilized for the mini-test, and only minor improvement alterations were required. Four injection wells and six producing wells were drilled, and four of these wells were cored.

A program was initiated for determining the residual oil saturation after waterflooding in the project area by utilizing various complementary techniques. These methods included comprehensive core analyses, well-logging, and single-well tracer tests.

FLUID SYSTEM DESIGN

At the beginning of this reporting year, the basic micellar-polymer fluid system design work had been completed by Marathon. Two micellar slug formulations (using different sulfonate brands) plus a list of polymers (polyacrylamide and polysaccharide) that had performed satisfactorily in the lab were presented to Long Beach, along with their performance data and quantity requirements. Bids were solicited for the required chemicals and Long Beach selected Stepan Chemical Company as the sulfonate supplier. The possible polymer suppliers were narrowed to two polyacrylamide manufacturers.

Further tests were to be run by Marathon to furnish additional data to aid the City of Long Beach in making the final polymer selection. Details of the final system design work, which was performed by Marathon Oil Company, are presented in Appendix A.

CHEMICAL PROCUREMENT AND HANDLING

A purchase order and Letter Agreement was submitted to Stepan Chemical Company for the manufacture and delivery of a 5/3 blend of Petrostep 450 and 465, 60 percent active sulfonate. Manufacturing operations began in early August 1978. The two sulfonates were manufactured in small batches consecutively and then blended together. This blend was mixed with about 11 weight-percent cosurfactant--Conoco's Alfonic 610-50--and transferred to a 15,000-barrel holding tank where it was to be stored until the entire sulfonate batch was manufactured.

Quality control to the specifications outlined by Marathon was considered essential to assure that the manufactured sulfonate would have the properties required for formulating the micellar slug. Therefore, a commercial laboratory (ARRO Laboratories) was retained to conduct the Viscosity-Alcohol Range Test designed by Marathon.

After Stepan alternately manufactured each batch of Petrostep 450 and Petrostep 465 and blended in the ratio of 5/3, samples were taken from the mixing tank. One sample from each batch--before and after Alfonic 610-50 addition--was provided to the commercial laboratory, which also witnessed the sampling. Duplicate samples were forwarded to Marathon. The sampling procedure was performed in this manner in order to meet the specifications outlined by Marathon.

Stepan Chemical Company completed manufacture in mid-November of 4.5 million pounds of the petroleum sulfonate ordered for the micellar-polymer project. This product was blended with about 500,000 pounds of Alfonic 610-50 in order to reduce its viscosity for better handling.

After manufacture and blending, the final sulfonate-alcohol blend in the storage tank was circulated for several days at about 140°F. Samples were taken by ARRO Labs on November 22, 1978. The samples were analyzed and found to conform to the quality control specifications prescribed by Marathon. Duplicate samples were forwarded to DRC where slugs were formulated in order to use these composite samples for testing in core floods.

Immediately after the decision was made to initiate micellar injection with the latest slug formulation, Stepan

Chemical Company was authorized, on January 10, 1979, to commence shipment of the sulfonate-alfonic blend. This first shipment was authorized during a period of extreme weather conditions in the Chicago area and some difficulty was experienced in transferring and shipping the initial batch. Coincidentally, an unusually severe cooling trend in California created a regional shortage of heating oils and intermediate feedstocks. As a result, the hydrocarbons required for the micellar formulation were practically unobtainable, with no guarantee of continuing supplies. The sulfonate shipping-order was cancelled after three tank cars had been loaded and shipped. This postponement of micellar slug injection now is indefinite until there is assurance of a continuing supply of the hydrocarbons--adequate to fulfill total requirements of the project. In the meantime supplies of gas-oil and diesel were committed to meet the requirements for formulating a micellar slug from the sulfonate initially shipped.

The three tank cars of sulfonate and alfonic blend--shipped from Stepan Chemical Company just prior to suspension of the micellar injection operations--arrived in Long Beach during February 1979. No major logistic problems were experienced during delivery. The tank cars--which arrived individually--were routed to the railroad spur at the Micellar-Polymer Injection Plant and off-loaded. No major problems occurred during the operation and each tank car was emptied within an 8-hour period after the sulfonate was steam-heated to a range of 160-180°F. It was necessary to roll the tanks while heating in order to ensure a uniform mixture. The sulfonate-alfonic blend was mixed with gas-oil and diesel oil, but the additional alfonic and water components of the slug will be added just prior to injection.

PRODUCTION AND INJECTION OPERATIONS

Continuous injection into project Wells FT-1, FT-2, FT-3, and FT-4 was initiated on June 12, 1978. Previously, the wells were on injection for two days during May 1978 to provide short-term pulses of 1600 B/D for the pressure transient test. The "pre-flush" was initiated in June at an injection rate of 500 B/D per well using produced water from the Pier "A" Water Injection Plant. The produced water is moderately saline with a chloride-ion concentration of about 18,000 ppm and a TDS of almost 30,000 ppm. Early performance indicated that the injectivities were satisfactory as shown on the attached performance graphs. Injection Wells FT-2, FT-3 and FT-4 continue to exhibit good injectivities; however, each has shown a minor decline since beginning injection. Well FT-1--the mini-injectivity test well--demonstrates the lowest injectivity, apparently due to the bank of polymer previously injected. The injection rate into each of these wells has averaged about 450 B/D during the pre-flush period. Spinner surveys have been run periodically in order to monitor the injection profiles.

All of the project's producing wells were put on production on June 15, 1978. All wells were initially equipped with 2-1/4" rod pumps with 3/4" rods in 2-1/2" tubing. The pumps were designed for nominal rates of 600 B/D; however, because reservoir pressure was above hydrostatic pressure, the wells initially produced at about 800 B/D gross rates with high fluid-levels. The wells have been scheduled for weekly testing with each well being produced into a test tank for a 22-hour period.

Well T-103--in which an attempted repair of a casing failure was aborted--was abandoned and redrilled from the existing 12-3/4" surface casing. After running and cementing 10-3/4" surface casing to 600', 9-7/8" hole was drilled to 2880' where the bit was changed to a Christiansen 7-1/2" diamond core-head with plastic-sleeve core barrel. The well was cored to 2955' with about 95 percent recovery attained. After coring, the hole was opened to 7-5/8" and a suite of well logs was obtained. The shoulder was opened to 9-7/8" (to 2900') and 7" casing was run and cemented at 2900'. The well was cleaned out to bottom, the hole was under-reamed to 12", and 5-1/2" liner was run and gravel packed.

Numerous problems have been encountered in the producing wells. During the nearly one year period since initiation of injection, these project wells have been off production about 18 well-months, representing more than 25 percent downtime. During the first three months of operation severe corrosion problems were encountered which required major remedial work in several of the producers. The producing rate in Well T-101 dropped from 700 B/D to 200 B/D; a diagnostic job was performed and the well was found to be sanded-up. Heavy corrosion was found on the entire rod string. Well T-102 was shut-in and the rods, pump plunger and standing-valve were pulled to run a static migration survey. The rods were badly corroded and a hole was found in the tubing, together with severe corrosion damage to all joints. The severe corrosion found in Well T-102 and several other wells results from the difficulty of treating these wells with corrosion inhibitors because of the inordinately high fluid levels. Reservoir pressure was about 200 psi over hydrostatic when this project was begun and the rod pumps had insufficient capacity to adequately reduce fluid levels. Therefore, it was decided that pumps with greater capacity should be installed.

During this early period, moderate to severe corrosion was experienced in most of the project producing wells. Iron sulfide scale was recovered from nearly all of these wells when they were pulled for remedial work. Analysis of a culture sample verified that this watered-out portion of the HXa reservoir had been seriously infected with "desulfo vibrio". These bacteria have proliferated in this environment where

the injection of low temperature, high sulfate water historically has reduced the reservoir temperature and provided nutrients for an ideal incubator.

A fluid-entry survey run in Well T-104 showed interstringer migration. This well was producing with a very high fluid-level and had not been pumped-off since being produced. The survey indicated that 650 B/D was being produced from the upper 30 feet of the HXa Sand while about 150 B/D was entering the liner from an interval located approximately 20 feet off bottom, migrating downward, and exiting into another stringer about 10 feet off bottom. A static survey performed with the well shut-in confirmed the downward migration but showed no migration into the HXb Sand (below the HXa).

In order to determine the extent of the migration problem found in Well T-104, fluid-entry surveys were run in several nearby wells--Wells T-100, T-101 and T-102. These wells bracket Well T-104. No interstringer migration occurred in any of these wells demonstrating that the problem was local and was, possibly, the result of communication between the HXa and HXb Sands through the well-bore of a nearby well.

Because of these problems, it was considered essential that all wells in the project be pumped-off in order to: (1) mitigate the north-south pressure gradient with consequent potential drift, (2) minimize interstringer migration and subsequent loss of chemicals, (3) reduce operating fluid-heads to permit effective corrosion treatment, and (4) establish pilot area pressure equilibrium. Therefore, all producing wells were converted from rod pumps to submersible pumps having average operating pump capacities of 1200 to about 3000 B/D. After the installation of these larger pumps, the wells were pumped-off, the formation pressures were drawn down and interstringer migration was arrested. However, these high producing rates contributed to some additional problems. Liner failures occurred in two wells, T-100 and T-101, shortly after they were converted to submersible pumps.

TRACER TEST PROGRAM

A tracer program was scheduled for the pilot area in order to detect premature pattern breakthrough as a test for reservoir heterogeneities, to determine conforming pore volumes in the pattern, and to monitor the integrity of the chemical slugs. Technical assistance for the tracer program has been provided by R. M. Weinbrandt, Aminoil USA, Inc. Aminoil USA is one of the parent companies of Long Beach Oil Development Company (LBOD), and LBOD is the Field Contractor for the Department of Oil Properties, City of Long Beach.

Implementation of this tracer test program was contingent upon obtaining adequate production rates and good injection

well profiles as well as maintaining reasonably steady-state conditions within the flood pattern. Larger capacity pumps were installed and most of the producers were pumped-off.

The objectives of the proposed tracer test program are to:

1. Determine whether gross heterogeneities exist in the pattern. Such problems would be indicated by early tracer breakthrough, within a matter of weeks. However, this possibility was regarded as remote. Nevertheless, if premature breakthrough would have occurred, the cause would have had to be corrected.
2. Determine the conforming pore volume in the pattern by matching observed tracer elution profiles with model calculated profiles.
3. Monitor micellar slug movement and integrity.
4. Monitor polymer buffer movement and integrity.

Since the micellar-polymer process--as it will be applied in the Wilmington Field--involves sequential injections of preflush, micellar, and polymer slugs, efforts should be made to utilize the existing components in these slugs as tracer materials. The simplest tracer in all of these slugs is the salinity. Formation water is approximately 30,000 parts per million TDS, while the micellar slug and the polymer slug will be mixed in fresh water. The salinity gradient--while an insensitive tracer--is nonetheless available and will be incorporated in the program.

During preflush, four different alcohols (methanol, ethanol, isopropanol, and n-propanol) were scheduled to be injected in each of the four different injection wells in the project. The two end injection wells, FT-2 and FT-3, were also to be tagged with thiocyanate. The purpose of supplementing the alcohol with the thiocyanate tracers in the two end wells was to ensure that adequate data could be obtained because of uncertainty as to the degree of biological or physical degradation of alcohol in the reservoir environment. Since ethanol and n-propanol are the most likely alcohols to degrade, they were injected with the thiocyanate in Wells FT-3 and FT-2, while methanol was injected in Well FT-4, and isopropanol in Well FT-1.

The micellar slug formulation includes two components, an alcohol and a sulfonate, which can be used as tracers for the slug. Sulfonate can be detected directly by lab tests for as low as a 10 parts per million concentration. Alcohol can be detected on a gas chromatograph in the same analysis that

is performed for the four alcohols used for the preflush tracer. The fresh water used in the micellar slug will also serve as a salinity tracer.

Tritium will be added to the leading edge of the polymer slug at the injection plant to provide a tritium tag of all pilot injection wells. Additional tracing of the polymer slug will be afforded by the fresh water in which the polymer is dissolved.

The tracer program in the project area was initiated in mid-October with different alcohols introduced into each of the four injection wells. Thiocyanate was also injected in the two end injectors. The following volumes and concentrations were injected into the respective wells:

<u>Well No.</u>	<u>Date</u>	<u>Tracer</u>	<u>Amount</u>	<u>Approximate Concentration ppm</u>
FT-1	10/12-13/78	Isopropanol	275 gal.	10,600
FT-2	10/10-11/78	n-propanol	275 gal.	9,700
		Thiocyanate	1925 lbs.	10,200
FT-3	10/10-12/78	Ethanol	275 gal.	10,300
		Thiocyanate	1925 lbs.	11,000
FT-4	10/12-13/78	Methanol	275 gal.	10,000

The injectors were each maintained at a rate of about 500 B/D during and after the tracer injection period. Spinner surveys were run to monitor the injection distribution. Injection has been maintained at fairly constant rates. Efforts have also been made to keep the producing wells on production. However, as previously indicated, two of the wells were off production during much of October and November and a third, Well T-103, was off during most of this time while being redrilled. All active producing wells in the project area are being monitored for tracer breakthrough. Several wells outside the pilot area are also being monitored. Wells Z-231 and Z-81, which are located across the Pier "A" fault from the pilot area, and Well Z1-17 one location south of the area, are being periodically sampled to confirm the effectiveness of the fault barrier and to detect fluid bypassing along the fault to the crestal producing area. However, Well Z-81 has subsequently failed and will not be returned to production.

Sampling schedules have been established for both (1) the producing wells located in the pilot area and (2) those producing wells located outside the area. The project area wells are scheduled for a higher testing frequency. These wells were sampled each tour for the first two weeks, then once daily for the next two weeks, then three samples per week, and finally one sample per week. The secondary wells were sampled once daily for the first two weeks, then three times

per week for the next two weeks and finally one sample per week. The samples are being analyzed for each of the four alcohols and thiocyanate.

In order to minimize costs for laboratory work, a schedule was established whereby only composite samples are to be analyzed until a tracer is detected. These composite samples are blends of small portions from each well sample. After a tracer is detected, the source producer is isolated and each sample from that well is tested independently. A composite sample from the remaining wells will continue to be analyzed.

The earliest chromatograph run showed a strong signal for isopropanol from all production wells. Isopropanol had been injected in Well FT-1. However, it soon became apparent that an extraneous source was responsible for the aberrant behavior. A background test had not been run on the producing wells prior to sampling for tracers, but a brief investigation revealed that all producers are being treated with corrosion inhibitors, most of which contain a base of iso-propyl alcohol.

Early in November a low concentration of methanol, 4-ppm, was detected in Well T-104. Methanol had been injected as a tracer in Well FT-4 located directly across the pilot pattern from well T-104. As noted on the attached performance curve, this well was producing at an exceedingly high rate, over 2500 B/D gross fluid, for more than a month prior to tracer detection. Because the methanol tracer peaked at only 5-ppm concentration for a short duration, the early detection of tracer is not considered significant. Subsequently, on about December 8, 1978 a low concentration, about 6-ppm, of thiocyanate ion was detected in Well T-105. This well is located about 300 feet southeasterly of the southernmost injection well, FT-2, in which tracers of both SCN and NPA had been injected.

To date, there has been no indication of n-propanol breakthrough in any of the sample analyses. Thiocyanate is still being detected at about the same concentration and we will continue to closely monitor producer T-105.

Traces of thiocyanate were also detected in Well T-102 in mid-January. This latter well is located on-strike with and directly opposite the northernmost injector, Well FT-3, into which SCN was injected in mid-October. This behavior was encouraging because it confirmed the earlier methanol response in Well T-104 --which indicated that the fluid drift problem was minimal in this area despite the historical pressure gradient in the reservoir proper. Unfortunately, Well T-102 failed soon after the tracer was detected precluding a quantitative determination of reservoir conformance in this portion of the pilot area.

RESERVOIR DATA OBTENTION

In order to collect basic reservoir data for evaluation of the project, a comprehensive coring and well-logging program was performed during the redrilling of Well T-103. A contract modification to the Wilmington Micellar-Polymer Project, which provided for the determination of residual oil saturation and related data for the HXa sand, was executed. Results of the core analyses and well logging--obtained under this program and from information previously determined--are being interpreted, correlated, and rationalized. The final results will be presented in a separate report, "Residual Oil Saturation Determination, Wilmington Micellar-Polymer Project." This data procurement program has involved the following tasks, as described:

Core Well T-103-A

Well T-103-A was redrilled, using a 9-7/8" bit, to within 20 feet of casing point above the top of the HXa interval. Coring was initiated on October 21, 1978 with a Christiansen 7-1/2" diamond core head on a plastic-sleeved core barrel. Cores were cut in a low water-loss, clay-base mud. Fifteen cores were cut and approximately 75 feet of material was cored. Core recovery from this very unconsolidated sand was excellent, with about 95 percent recovery from the 55 feet of HXa to HXb-15 sand interval cored. The cores were cut into approximate 3-foot lengths and frozen at the wellsite.

Electrical Well Logging

A suite of open-hole logs was run by several service companies. They included the following:

- (a) Micro-Spherically Focused Log (MSFL)
- (b) Dual Induction Laterolog (DIL)
- (c) Bore-Hole Compensated Sonic w/Gamma Ray (BHC-GR)
- (d) Formation Density-Compensated Neutron-Gamma Ray (FDC-CNL-GR)
- (e) Microlaterolog (MLL)
- (f) Dielectric Constant Log (DCL)

The following cased-hole logs were run after the hole was under-reamed to 12 inches and the perforated liner was set and gravel packed:

- (a) Dual Spacing Thermal Neutron Decay Time (TDT)
- (b) Dual-Detector Neutron Lifetime Log (NLL)
- (c) Carbon-Oxygen Log (C/O)

Numerous computed logs are being prepared using information derived from the aforementioned basic well logging tools. These computed logs include the following:

- (a) Saraband - Presents the basic reservoir formation characteristics utilizing open-hole logs.
- (b) Production Management Log (PML) - Complements information derived from open-hole logs with that from the TDT.
- (c) Cased-Hole Exploration Services (CHES-1) - Combines data derived from the Carbon-Oxygen and Neutron Lifetime Log with that from the open-hole logs. This will provide similar reservoir data as that obtained using (a) and (b) above.

Core Analysis

The frozen core material obtained from Well T-103-A was packed in dry ice, crated and shipped to Core Laboratories, Inc. in Oklahoma City where a comprehensive study of the reservoir sand characteristics was made. The cores were slabbbed and the slabs were mounted in plaster. These slabs were photographed in both ultraviolet and color and then returned to Long Beach. Staff geologists correlated the core slabs with electric well logs and prepared a detailed core description.

The core laboratory obtained more than 100 plugs from the frozen core--duplicate samples from each foot of sand cored (46 feet) and three sets of eight samples selected at random. One set of samples from each foot of sand cored was used for conventional analysis and determination of permeability and porosity values under a confining pressure of 1600 psi, with the sample compacted dry. The second set of duplicate samples was used for the determination of porosity at 1600 psi confining pressure for samples compacted wet.

Comparative values of porosity were determined on the two sets of eight randomly selected samples for core-samples compacted liquid-filled and dry, respectively. These values were run at simulated net overburden pressures of 350, 800, 1600, and 2000 psi.

The average values of porosity and permeability determined at 1600 psi confining pressure are about 32.8 percent and 283 millidarcies, respectively. These data were presented in the preliminary reports prepared by Core Laboratories, Incorporated.

Other special analyses, performed on core samples obtained from Well T-103-A, include the following: (1) waterflood susceptibility tests, (2) formation factors, (3) resistivities and (4) capillary pressure tests.

Partitioning Tracer Test

The single-well tracer test for residual oil saturation determination--licensed by Exxon--was performed on Well T-103-A

during February and March 1979. This work was performed by personnel from Union Oil Scientific and Technology Division and utilized their skid-mounted module for partitioning tracer testing.

Prior to testing, some concern was expressed regarding the amount of fluid drift in the HXa sand through the pilot area and the consequent effect on the test. The drift rate strongly influences the partitioning tracer test. A high drift rate would have required an ester with a high hydrolysis reaction time; e.g., propyl formate. In fact, it was considered possible that the drift rate could be high enough to negate test results.

Accordingly, a drift rate measurement test was initiated on January 29, 1979. The injection water was tagged with a methanol tracer--for the material balance--and isopropanol was injected to tag the end of the slug. After a shut-in period of about a day the well was put on production. The fluid was sampled until the concentration-production profile indicated that most of the tracer had been produced. A computer match indicated a drift rate of 0.7 feet per day. This rate was considered acceptable and the partitioning tracer test was scheduled.

In February, the skid-mounted test module was moved to the well location and the first phase of the partitioning tracer test--the mini-test--was commenced. The mini-test is intended to lay the groundwork for the subsequent main test. The two tests follow the same sequence, but the results from the mini-test are intended to determine whether some adjustment should be made for the main test.

The determination of residual oil saturation by the partitioning tracer method required the following sequence:

1. A slug of tracer tagged water was injected into Well T-103A in three phases. The first portion contained an ester--ethyl acetate--and methanol, the second portion contained only methanol and the last portion contained only isopropanol.
2. The slug is kept in the formation for a selected period of time so that part of the ester hydrolyzes to form alcohol.
3. The well is placed on production, samples of the produced water are analyzed for the tracer chemicals and--with careful sampling and metering of the produced fluids--a concentration-production profile is made.
4. Injection and production profiles are run several times during the test. This information and pertinent reservoir parameters are read into a computer model.

The residual oil saturation is obtained by establishing the best fit between the computed and the measured chemical-concentration data.

Union Research reported that the results of the mini-test were good. The analyses indicate that the residual oil saturation in the vicinity of Well T-103 is $39\% \pm 2\%$. The mini-test results also indicated that the three-day soak period was not quite adequate for optimum hydrolysis of the ethyl acetate and that the soak time for the main test should be extended.

The main test was initiated on March 3, 1981 after about 2000 barrels of chemical free water had been injected. After a 2580 barrel slug of chemically tagged water was injected, the well was shut-in for a seven-day soak period, during which a pressure fall-off test was made. During the soak period an adjacent producer, Well T-100, went off production with a pump failure. The failure of Well T-100 caused a 10-psi increase in pressure in Well T-103-A within one day. This upset of reservoir stability has complicated reservoir matching for the main test. Further simulation of the main test has been postponed, because the results of the mini-test were considered excellent and additional time would have been required to investigate other theories.

TABLE I
RESERVOIR CHARACTERISTICS
HXa SAND
(Interim)

Porosity	32%
Interstitial Water	30%
Permeability (Air)	439 md.
Oil Gravity	17° API
Oil Viscosity @ Res. Conditions	25 cp
Reservoir Temperature (Original)	145° F
Original Mobility Ratio	3.2
Project Area	11 Acres
Net Sand Thickness	52 ft.
Depth (VSS)	2900 ft.
Current Oil Saturation	38% PV
Pattern Pore Volume	1.42 x 10 ⁶ Bbls.
Current Oil-in-Place	540,000 Bbls.

LOS ANGELES BASIN OIL FIELDS Figure 1

AXIAL CROSS SECTION, FAULT BLOCKS II to VI Figure 3

HX SUBPOOL, UPPER TERMINAL ZONE, FAULT BLOCK VI Figure 4

ELECTRIC LOG

SELF-POTENTIAL
40 mv

RESISTIVITY
12 ohms

HX SANDS, ELECTRIC LOG INTERVAL Figure 5

PROJECT AREA MAP, HXa SAND Figure 6

APPENDIX A

WILMINGTON MICELLAR-POLYMER PROJECT

FLUID SYSTEM DESIGN

POLYMER AND FINAL SYSTEM DESIGN

Prepared by: Wayne R. Hause
Denver Research Laboratory
Marathon Oil Company
Littleton, Colorado 80160

The fluid system design work was performed by Marathon at its Denver Research Center. The core flooding work was performed using HXa Zone reservoir material. Special 5" cores were cut in several wells using plastic-sleeve core barrels. The cores were frozen at the well site and shipped to Marathon's Denver Research Center (DRC) where they were cut into 2" disks and wrapped in plastic. A hole was drilled in the center of each disk to serve as the injection point for the radial core floods. The cores were saturated with Wilmington crude and then waterflooded with Wilmington formation water. The various micellar-polymer formulations were then injected in scaled-down volumes to measure oil recovery efficiencies.

Evaluation work on the two polymers commenced. Core floods were run using the prototype Stepan slug (29993) which had been selected by Long Beach for this project. The goal of this work was to determine a minimum concentration of each polymer product necessary to furnish the desired mobility control. This information would then be used by Long Beach to make the final polymer selection.

The prototype Stepan slug (29993) was to be used for all floods. The only variables were to be the polymer types and concentrations. As it turned out, it was not possible to use the prototype slug formulation as such because the hydrocarbons had been changed. Diesel had been substituted for the kerosene and a heavier vacuum gas-oil was substituted for the original gas-oil for cost and availability reasons. Field samples of the various components were incorporated into the slug used for the core floods as they became available.

Table I lists the results of 24 core-flood runs (868-898). With the exception of run 868, all runs were made with slugs having the basic composition of 29993. Samples of the new gas-oil, diesel and alfonic were obtained and were incorporated into the slug compositions. Various polymers were tested at differing concentrations as recorded in Table I. It can be seen that the parameters normally used to evaluate core flood results--namely: final oil saturation, oil recovery (percent pore volume and percent oil-in-place), and oil recovery per volume of injected slug--were generally poor for slugs 31823A, 29993A and 31903. Poor slug performance masked any variance in recoveries that may have been caused by different polymers. Marathon, at this point, thought the slug problem was caused by the hydrocarbon substitutions. Therefore, it was decided to delay further polymer optimization work until the slug problem could be solved.

Table II shows results of core floods run to correct the slug problem. All core floods run from this point used slugs made from the sulfonate manufactured by Stepan for this project. It should be noted that samples from the manufactured sulfonate matched the Stepan sulfonate samples used during the slug design phase. To facilitate handling, Stepan blended 2/3

of the required Alfonic 610-50 with the sulfonate at their plant. The samples used in the core floods were taken from Stepan's tank after the two sulfonates (Petrostep 450 and 465) and the alfonic had been blended.

Core floods 899 through 905 used field samples of hydrocarbons and the Stepan sulfonate-alfonic blend. The remaining alfonic, which was to be blended in at the test site, had not been received in Long Beach so a sample of the alfonic--that supposedly was from the alfonic batch to be delivered to Long Beach--was obtained from Sellers Chemical Company and used in these floods. The basic components of the six different slugs were as just described. The only difference being the ratios of the two hydrocarbons. Core flooding results were unsatisfactory.

Runs 906 through 909 used slugs with two compositional changes. First, a different sample of the Stepan sulfonate-alfonic blend was used. Marathon continued to receive samples of the blend throughout the period of sulfonate manufacture. Each subsequent sample from the tank containing the blend became more representative of the properties that the final composite blend would have. Very little difference was seen in these samples, so for all practical purposes, the timing of the sulfonate-alfonic blend sampling had no effect on the slug properties. The second difference in the slug was that the actual sample of the alfonic that was delivered to the test site in Long Beach was substituted for the Sellers sample. These core floods were also unsatisfactory.

Core flood 910 used a slug where part of the diesel was replaced with kerosene to more nearly match the composition of the prototype slug 29993. The results were again disappointing.

At that point, Marathon began to suspect that the problem lay with the alfonic rather than the switch in hydrocarbons. Floods 912, 913, 916, 917 and 928 were run with normal butanol added to the slug. Recoveries were slightly better but this did not completely solve the problem. For runs 914 and 915, the hydrocarbons were (kerosene and original lighter gas-oil) in the prototype slug were substituted. Again, poor results were obtained. The poor recovery using a slug with the original hydrocarbons as the best evidence to date that the problem was not the hydrocarbons but might be the alfonic.

The various alfonic samples were investigated. The four sources of alfonic samples are listed below:

1. Conoco sample - original sample that was received from Conoco and used in the design of the prototype slug.
2. Sellers sample - supposedly taken from the batch

destined for Long Beach.

3. Stepan sample - taken from the batch shipped to Stepan for blending with sulfonates.
4. LBOD sample - taken from the batch delivered to the Long Beach site for final blending.

Figure A-1 shows a plot of slug viscosity versus alfonic concentration. This graph shows that none of the other samples match the original Conoco sample. The two field samples were fairly uniform and were closer to the Conoco sample than to the Sellers sample. The problem was (as indicated by these data) that samples 2, 3, and 4 were more oleophilic than the Conoco sample resulting in decreased oil recovery efficiencies.

It is understood that Conoco normally manufactures the alfonic 610-50 product, but Conoco has contracted with Sellers Chemical Company to also manufacture it during periods of high demand. The Conoco sample was furnished by Conoco, but Marathon was unable to ascertain whether it was a laboratory prepared or a plant sample. Regardless of its source, it was not representative of the subsequent samples received.

The Sellers sample was furnished by Sellers and supposedly taken from the batch destined for Long Beach. Its properties (for the micellar solution application) were the farthest from the properties of the Conoco sample used in the design work, but fortunately it was not representative of the alfonic actually delivered to Long Beach.

The Stepan and LBOD samples performed similarly in the viscosity-alcohol range tests, but their variance from the Conoco sample was sufficient to adversely effect the resultant slugs' oil displacement efficiency. The alfonic shipped to Stepan was manufactured by Sellers. Sellers probably made the alfonic sent to Long Beach also, but this is not certain.

Slug 37006, made from the samples of the actual field components, was used in runs 918 through 925. The best recoveries were from runs 920 and 925, where a hydrophilic alcohol was added to the polymer spike (first 10% pore volume of polymer injected). The field alfonic samples (3 and 4) tended to make the slug more oleophilic than the Conoco sample used in the original slug design. The addition of a hydrophilic alcohol to the polymer made it more miscible with the slug.

Long Beach Department of Oil Properties gave approval to the use of slug 37006 with the subsequent addition of the hydrophilic alcohol, but they wondered if it wouldn't be better to add the alcohol to the tail end of the slug rather than the front end of the polymer. Long Beach also noted that better core floods were run in core material from Well T-102 rather than the Well FT-1 core material used in the

previous runs. Marathon agreed to perform additional core floods to answer these questions in addition to finalizing the polymer optimization work.

Referring to Table A-III, core floods 935 and 936 were run with the hydrophilic alcohol added to the tail end of the slug. This procedure did not appear to be as effective as adding it to the polymer spike. Runs 935 and 936 utilized the same fluid system. The only difference was that 935 was run in a Well T-102 core, while 936 was run in a core from Well FT-1. The results were comparable.

Normal butanol was determined to be the most cost effective hydrophilic alcohol for this system. A 0.5 volume percent was used in most tests. Tests 941 and 942, where 1.0 volume percent was used, indicated that the additional butanol was not warranted.

Figure A-2 graphically depicts the different phases of the slug optimization work as related to oil recoveries. The average oil recoveries, expressed as recovery (percent pore volume and percent oil-in-place) and barrels of oil recovered per barrel of slug injected, for each phase are plotted. The figure shows that the final slug is at least as good and probably better than the prototype slug 29993.

Core floods 926 through 934 (except 928) were run for final polymer evaluation using different product concentrations of each vendor's most promising polymer. Slug 37039, which was used for all of these floods, is the same as slug 37006 except for the hydrocarbon ratio. A 0.5 volume percent of butanol was added to the polymer spike on each run. Data from these runs are shown on Table A-III. Figure A-3 shows plots of relative reciprocal mobility data versus concentration for each polymer. Data from previous core floods had shown that a relative reciprocal mobility of at least 100 cp was necessary for mobility control in this reservoir.

Marathon transmitted these data to Long Beach along with the following comments:

1. From an oil recovery standpoint, the two polymers are equivalent.
2. Polymer A exhibits fewer face plugging tendencies.
3. The laboratory data indicate that Polymer A would have better injectivity in the field than Polymer B.

Long Beach reviewed the data presented and considered the following (not necessarily in this order) in making their selection:

1. Incremental oil recovery.
2. Final oil saturation.
3. Required polymer concentrations.
4. Face plugging tendencies.
5. Cost.

On the basis of these considerations, Long Beach selected Polymer A which was American Cyanamid's Cyanatrol 960-S, an emulsion type polyacrylamide polymer. However, Marathon observed a definite degradation over a period of time of the Cyanatrol 960-S laboratory sample. Another sample (believed to be from the same batch) was obtained from the manufacturer. This sample had the same properties as the degraded laboratory sample when it was received some six months previously. It was reasoned that the degradation of the lab sample was caused by exposure to oxygen each time the bottle was opened. Since this situation would not be encountered in the field, it was concluded that this problem should not be of concern.

Laboratory core flooding work is now essentially completed. The only anticipated work will be to run a series of core floods using the field-mixed slug. Varying pore volume percentages of slug will be used so that an injected slug pore volume versus oil recovery relationship can be established. The core floods run during the design work used approximately 7% pore volume of slug. Since the project pore volume was not known at the time the sulfonate was ordered, it had to be estimated. The actual amount of slug injected will be the amount that can be made from the previously estimated sulfonate requirements. The actual volume of injected slug should be 7.5% +/-0.5%.

A basic problem relating to the need for consistent properties of micellar slug components became very apparent in this project. Marathon was aware of this problem and requested samples of available field materials for use in the laboratory design work. The problem was that some samples either were not representative or, for reasons beyond control, some of the components became unavailable.

The sulfonate presented no problem for this project although it had in some previous projects. In this case, Stepan was furnished with special quality control specifications which they followed diligently. It involved frequent sampling and testing during manufacture. The result was a uniform product that met specifications.

The problems encountered because of the difference in the various samples of the co-surfactant (Conoco alfonic 610-50) used for the project have already been described. Each of the four samples was analyzed and compared to Conoco's specifications for this product. The results are shown in Table IV. As noted, Marathon performed most of the tests. Marathon stated that the fact the analyses do not check very well with specifications may in some cases be due to different analytical techniques. For whatever the reason, the properties--with the exception of the pH--generally do not fall within the specified limits. Marathon could draw no obvious conclusions from these analytical data that would indicate one sample was better than another for use as a co-surfactant in a micellar solution. Both hydroxyl number and specific gravity rank the four samples in roughly the same order as would be determined from the viscosity-alcohol range test on the bench. However, the numerical difference is small and would be difficult to use in a quality control test for this type of material.

Maraflood (TM) slugs usually employ some type of hydrocarbon. Very often refined hydrocarbons are used. The actual composition of refined hydrocarbons--for example kerosene, diesel, gas-oil, etc.--vary from refinery to refinery and can vary within a single refinery over a period of time. This variance makes little, if any, difference for the normal use of these products. It does, however, make a difference if that use is as a micellar solution component. In most cases the problem can be overcome by varying the amount or type of cosurfactant used or by varying hydrocarbon ratios if more than one is used. Many times the necessary adjustment results in a more expensive micellar solution.

For this project it became necessary to change the hydrocarbons after the proposed slug design had been finalized. The change was accomplished; however, a lot of time and effort was expended trying to adapt to the new hydrocarbons before it was discovered that the main problem was the co-surfactant, not the hydrocarbons.

At the present time, this project is being delayed because the required volume of diesel oil is not available. One possible source was recently investigated. Although this material did meet the gravity and viscosity specifications furnished by Marathon, it was rejected because it could not pass the viscosity-alcohol range test. It may have been possible to utilize this particular diesel by adding large amounts of co-surfactant but this would not have been practical from an economic standpoint and would still be questionable from a system design standpoint.

The basic problem of quality control is that the specifications normally set up for these products are not sufficiently precise for the micellar-polymer application. Marathon must

rely on the viscosity-alcohol range relationships to test micellar slug components. In this test all of the slug components are mixed except for the alcohol co-surfactant. Alcohol is then added in small amounts with the viscosity being measured after each addition. The resultant curve is then checked against a standard for this particular micellar solution. Obviously, the test is geared to a single micellar solution. This is a big disadvantage and points to the need for a method of testing that could be applied generally.

Table A - I
WILMINGTON MICELLAR POLYMER DOE PROJECT
RADIAL CORE FLOODS - FROZEN H₂O CORE

Run No.	Slug No.	Polymer Type	Polymer* Body Concentration	Porosity	Permeability	Slug Size % PV	(1) Initial Oil Saturation Soi(%PV)	Residual Oil Saturation Sor(%PV)	(2) Final Oil Saturation Sorc(%PV)	(1) Recovery Waterflood (%PV)	Recovery Chemical (%PV)	Recovery Chemical (%OIP)	Recovery Chemical (Vol/Vol Slug)
868	27975	A	1500	29.38 (30.66)	41	6.92	72.92	37.06	7.05	35.86	30.01	80.97	4.69
869	29993	A	1500	30.58 (31.50)	60	6.50	67.86	34.08	8.81	33.77	25.28	74.17	4.11
870	31832A	A	1500	28.80 (28.95)	13	7.19	60.23	33.33	13.76	26.90	19.57	58.72	3.01
871	31832A	B	1500	31.05 (32.53)	26	6.51	56.66	23.12	10.11	33.54	13.02	56.29	2.29
871A	31832A	B	1500	29.05 (30.58)	12	6.88	66.12	34.60	13.50	31.52	21.10	60.98	3.35
872	31832A	A	1000	29.92 (31.02)	14	7.01	52.84	32.93	17.84	19.91	15.09	45.84	2.44
873	31832A	B	1000	29.73 (31.51)	23	7.00	60.09	30.58	14.72	29.51	15.85	51.85	2.55
874	31832A	C	800	29.46 (30.64)	15	7.16	51.22	22.71	8.59	28.51	14.12	62.16	2.26
877	31832A	B	800	30.44 (31.17)	11	7.03	60.44	29.31	16.33	31.12	12.98	44.29	2.13
878	31832A	B	600	29.70 (32.13)	30	7.14	57.64	24.47	9.59	33.17	14.88	60.83	2.37
879	31832A	C	600	31.98 (29.96)	10	6.39	51.49	30.55	23.31	20.94	7.24	23.70	1.42
883	29993	C	800	29.19 (30.09)	28	6.73	59.96	27.48	14.16	32.43	13.32	48.48	2.27
884	29993	D	800	29.89 (31.28)	16	6.65	60.69	27.91	16.46	32.73	11.45	41.04	2.01
885	29993	D	600	29.42 (30.27)	27	6.70	64.79	31.06	12.63	33.74	18.43	59.34	3.04
886B	29993	E	1000	29.39 (30.44)	7	6.94	57.53	27.61	15.46	29.92	12.15	44.01	2.04
887	29993	E	800	29.91 (30.28)	35	6.83	62.59	28.82	12.82	33.77	16.00	55.53	2.63
891	29993	C	1000	29.29 (29.36)	24	6.73	60.64	29.23	23.08	31.41	6.15	21.04	1.20
892A	29993	D	1000	27.95 (28.74)	17	7.15	66.41	31.47	17.57	31.55	13.89	44.15	2.23
893	29993	C	800	28.83 (28.54)	15	6.86	68.35	33.39	20.73	34.96	12.67	37.93	2.14
894	31903	C	1000	30.09 (30.95)	12	6.49	63.62	32.73	16.00	30.88	16.74	51.13	2.87
895	31903	E	1000	28.94 (30.30)	125	7.53	67.50	30.70	10.33	36.80	20.37	66.35	2.99
896	31903	E	800	28.48 (30.19)	30	7.78	59.26	28.14	11.11	31.11	17.03	60.52	2.48
897	31903	C	1200	30.69 (32.56)	—	6.59	64.65	32.33	10.86	32.33	21.47	66.40	3.54
898	31903	C	800	28.86 (29.83)	—	7.08	65.40	33.11	17.73	32.30	15.37	46.43	2.46

*PPM 100T Active Polymer

(1) Data corrected by estimate for oil holdup in outer ring.

(2) Value is as measured. Includes remaining reservoir oil plus hydrocarbon slug components

Porosity - Unbracketed values determined by the sum of fluids method; bracketed values by weight difference method.

Table A-II
WILMINGTON MICELLAR POLYMER DOE PROJECT
RADIAL CORE FLOODS - FROZEN H₂O CORE

Run No.	Slug No.	Slug Size % PV	Porosity %	Permea- bility MD	(1) Initial Oil Saturation Soi(%PV)	Residual Oil Saturation Sor(%PV)	(2) Final Oil Saturation Sor(%PV)	(1) Recovery Waterflood (%PV)	Recovery Chemical (%PV)	Recovery Chemical (%OIP)	Recovery Chemical (Vol/Vol)
899	31944	6.8	30.1 (31.8)	109	65.7	38.2	15.6	27.4	24.6	64.4	3.61
900	31945	6.7	29.8 (31.6)	83	73.4	39.1	18.7	34.3	22.3	57.1	3.31
902	31946	6.3	31.7 (32.0)	96	68.7	38.8	15.1	29.9	25.5	65.8	4.06
903	31947	6.5	30.5 (31.3)	91	62.5	30.8	12.1	31.7	20.6	66.8	3.16
904	31943	7.0	29.3 (30.4)	75	68.9	31.0	14.1	37.9	18.9	61.1	2.69
905	31949	6.6	30.8 (31.0)	16	64.5	33.6	12.4	30.8	23.1	68.6	3.51
906	36936	6.3	31.6 (31.8)	39	48.2	26.8	14.9	21.5	13.7	51.0	2.17
907	36935	6.8	30.3 (31.4)	62	68.9	35.3	18.0	33.6	19.2	54.5	2.84
908	36936	6.6	30.2 (31.9)	57	63.2	33.1	12.6	30.2	22.4	67.6	3.41
909	36938	6.5	30.4 (31.6)	32	59.9	27.6	13.3	32.3	16.2	58.7	2.49
910	36942	6.2	31.9 (32.2)	41	60.5	33.1	17.3	27.5	17.5	53.0	2.85
912	36943	6.4	31.3 (32.3)	59	63.5	33.5	14.1	30.0	21.2	63.3	3.31
913	36943	6.7	31.4 (32.7)	--	49.9	22.4	14.5	27.6	9.8	43.6	1.47
914	36994	6.6	29.8 (30.3)	104	65.0	35.2	22.5	29.8	14.6	41.4	2.22
915	36994	7.2	29.7 (30.8)	48	60.6	34.0	16.1	26.5	20.0	58.7	2.79
916	36943	7.0	29.7 (31.6)	32	59.7	33.7	13.3	26.0	22.4	66.5	3.20
917	36943	6.8	30.7 (31.7)	43	62.5	29.7	11.3	32.8	20.3	68.4	3.00
918	37006	7.1	29.1 (30.7)	18	61.6	32.4	12.0	29.2	22.4	69.2	3.18
919	37006	7.3	26.5 (27.2)	126	65.0	34.4	11.4	30.6	25.1 (3)	73.0	3.43
920	37006	6.7	30.0 (30.6)	174	68.2	37.1	9.7	31.1	29.3 (3)	79.0	4.39
921	37006	7.1	28.9 (29.9)	153	71.3	37.1	9.7	34.2	29.4 (3)	79.3	4.16
922	37006	7.0	28.8 (29.4)	116	68.0	33.1	10.5	34.9	24.7 (3)	74.4	3.53
923	37006	7.2	28.1 (28.9)	135	63.5	32.1	7.7	31.4	26.5 (3)	82.5	3.69
924	37006	7.4	29.0 (30.3)	46	64.7	27.9	11.1	36.8	18.9	67.9	2.57
925	37006	6.8	29.4 (30.1)	82	65.6	36.0	12.0	29.7	26.0 (3)	72.1	3.79

(1) Data corrected by estimate for oil holdup in outer ring.

(2) Value is as measured. Includes remaining reservoir oil plus hydrocarbon slug components.

(3) Runs on core samples from Well T-102, all others from Well FT-1.

Porosity - Unbracketed values determined by the sum of fluids method; bracketed values by weight difference method.

Table A-III
WILMINGTON MICELLAR POLYMER DOE PROJECT
RADIAL CORE FLOODS - FROZEN H₂O CORE

Run No.	Slug No.	Polymer Type	Polymer Product Body Concentration (PPM)	Porosity %	Permeability MD	Slug Size % PV	(1) Initial Oil Saturation S _{oi} (%PV)	Residual Oil Saturation S _{or} (%PV)	(2) Final Oil Saturation S _{orc} (%PV)	(1) Recovery Waterflood (%PV)	Recovery Chemical (%PV)	Recovery Chemical (%OIP)	(Vol/Vol Slug)
926	37039	A	4000	27.7 (28.5)	38	7.1	61.8	29.3	7.4	32.5	23.9	81.8	3.37
927	37039	B	2000	31.6 (32.1)	36	6.1	67.8	35.3	13.2	32.5	23.8	67.5	3.92
928	36943	A	4000	30.3 (31.2)	90	6.4	63.3	31.6	8.7	31.6	24.8	78.5	3.85
929	37039	B	2400	30.1 (31.1)	78	6.6	63.2	27.7	5.3	35.5	24.3	87.7	3.67
930	37039	B	1600	31.0 (32.0)	86	6.2	60.1	29.4	8.6	30.6	22.6	76.8	3.63
931	37039	B	1200	27.1 (27.9)	66	7.3	64.0	31.5	11.6	32.6	21.9	69.7	3.00
932	37039	A	4000	29.2 (29.8)	75	6.8	61.4	30.5	9.3	30.9	23.2	76.0	3.41
933	37039	A	3200	30.2 (31.9)	12	5.9	62.2	33.9	9.8	28.4	26.0	76.8	3.79
934	37039	A	2400	30.2 (31.5)	67	5.6	57.4	26.0	9.0	31.4	18.8	72.5	2.86
935	37039	A	4000	28.8 (29.0)	66	3.9	61.2	29.6	10.4	31.6	21.2	71.5	3.10
936*	36943	A	4000	30.2 (31.3)	41	2.9	62.6	32.4	10.3	30.2	24.1	74.3	3.44
941*	37039	A	4000	31.1 (31.7)	39	3.0	62.3	34.7	15.3	27.5	21.5	61.9	2.97
942*	37039	B	2000	30.5 (31.7)	54	6.8	60.2	32.0	10.8	28.2	23.1	72.3	3.41

*Core from FT-1, other runs from T-102.

(1) Data corrected by estimate for oil holdup in outer ring.

(2) Value is as measured. It includes remaining reservoir oil plus hydrocarbon slug components.

Porosity - Unbracketed values determined by sum of fluids method; bracketed values by weight difference method.

Table A - IV
ANALYSIS OF VARIOUS ALFONIC 610-50 SAMPLES

<u>Properties</u>	<u>CONOCO</u>		<u>Sellers</u>	<u>Analysis</u>	<u>Conoco</u>	<u>LBOD</u>
	<u>Specification</u>	<u>Typical</u>		<u>Stepan</u>		
(1) Hydroxyl Number	200-220	210	201	194	181	188
(1) Water Wt. %	0.1 Max.	0.03	0.35	0.49	0.51	0.40
(2) Color APHA	30 Max.	5	10	400	10	400
(1) pH of 1% Aqueous Solution	6-7	6.8	6.4	6.5	6.6	6.1
(2) Specific Gravity @ 60° F		0.95	0.9267	0.9421	0.9572	0.9500
(2) Viscosity cSt @ 100° F		11.7	10.4	10.9	12.4	11.4
Structural Formula $\text{CH}_3(\text{CH}_2)_n \text{CH}_2$ $(\text{OCH}_2 \text{CH}_2)_m \text{OH}$						
(3) Where n =		4-8	6.35	5.85	6.10	6.80
(3) and m =		~3.0	2.4	2.23	2.88	3.08

1 - Analysis by Marathon Oil Company

2 - Analysis by Hauser Laboratories

3 - Analysis by NMR (Nuclear Magnetic Resonance)

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MICELLAR - POLYMER FFOJECT
SLUG FORMULATIONS
VISCOSITY VS. COSURFACTANT CONCENTRATION

Figure A-1

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SLUG OPTIMIZATION
OIL RECOVERY DATA - CHEMICAL FLOOD

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RELATIVE RECIPROCAL MOBILITY
versus
POLYMER CONCENTRATION

Figure A-3

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