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BELL CREEK FIELD
MICELLAR-POLYMER PILOT DEMONSTRATION
FIRST ANNUAL REPORT, JULY 1976-SEPTEMBER 1977

By

Gary Operating Company
Prepared for DOE
Under Contract No. EY-77-C-02-4207

Date Published-February 1978

Bartlesville Energy Research Center
U.S. Department of Energy
Bartlesville, Oklahoma

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MICELLAR-POLYMER PILOT DEMONSTRATION
FIRST ANNUAL REPORT
JULY 1976—SEPTEMBER 1977

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MICELLAR-POLYMER PILOT DEMONSTRATION
First Annual Report
July 1976 to September 1977

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NOMENCLATURE

ΔAPI	$141.5 / (S_{pg} 60^\circ / 60^\circ F) - 131.5$
BBL	Barrel
c	Compressibility (1/psi)
cc	Cubic centimeter
cp	Centipoise
De	Effective dispersion rate (ft^2/sec)
FVF	Formation volume factor (RB/STB)
g	grams
h	Formation thickness (ft)
IBP	Initial boiling point
$k_j = k_{rj} K_a$	Permeability j species (md)
K_a	Permeability Air (md)
l	liter
L	Length of system (ft) for use in Péclet number. It is the core length in experimental work or the interwell distance in a model study.
md	millidarcies
mg	milligrams
$N_{ca} = k (\frac{dp}{dx}) / \sigma$	Capillary Number
$Np_e = L / \alpha$	Péclet number
PBTD	Plug-back total depth (ft)
POD	Products of distillation
ppm	Parts per million
psig	lbs/in^2 - gauge
PVT	Pressure-Volume-Temperature

RB	Reservoir BBL
RDB	Rotary Drilling Bushing
ROS	Residual oil saturation (see Sec.C, Chapter X)
SCF	Standard cubic feet
S_{or}	Residual oil saturation (% or fraction)
$S_{pg} \ 60^{\circ}$	Specific gravity at 60°F
STB	Stock tank BBL
STO	Stock tank oil
TD	Total depth (ft)
v	Interstitial velocity (ft/sec)
$\alpha = De/v$	Dispersive mixing length (ft)
μ	Viscosity (cp)
σ	Interfacial tension (dynes/cm)
ϕ	Porosity (% or fraction)

CHAPTER I

SUMMARY

Gary Operating Company is conducting a Department of Energy Pilot Demonstration to determine whether micellar-polymer flooding is an economically feasible technique for enhanced oil recovery from the Muddy Sand Unit 'A' Reservoir of the Bell Creek Field, Powder River and Carter Counties, Montana. During the first year of this project extensive reservoir studies, site and pattern selection, design and selection of an optimal micellar-polymer system, water flood history matching and preliminary process simulations by numerical models, and development of pilot injection and production wells were completed.

The major effort during the first contract year was the design for the Bell Creek pilot of two optimal micellar-polymer processes -- one oil-external and one water-external; and the concomitant development of a Selection Methodology by which to decide upon the more suitable process by means of a standard set of laboratory experiments and numerical simulations. This effort was completed. The oil-external design was selected for Bell Creek application based upon its superior performance in

the standard test series and simulations. The advantages of the Bell Creek oil-external design appear to be better recovery performance, mobility control, and protection against divalent ions.

CHAPTER II

INTRODUCTION

In response to ERDA Request for Proposal No. E(49-18)-2237, Gary Operating Company (GOC) was granted a contract EY-77-C-02-4207, originally E(49-18)-2237, to conduct a micellar-polymer pilot-scale demonstration in Bell Creek Field, Powder River and Carter Counties, Montana, Figs. 1 and 2. This demonstration project includes: 1) site selection, 2) micellar-polymer system selection, 3) site development, 4) performance prediction via numerical simulation, 5) field implementation of a micellar-polymer pilot flood, 6) monitoring and engineering analysis of the pilot performance, and 7) a final report.

The pilot is a contained 40-acre five-spot located in a representative watered-out part of Unit 'A' Reservoir in the Bell Creek Field, Figs. 3, 4 and 5. The pay is sandstone with an average thickness in the pilot area of eight feet, porosity of 29%, air permeability of 1,050 md, and a watered-out interwell residual oil saturation of 35%, which is the estimated available tertiary target. If the pilot is successful, future expansion of the process to the whole Bell Creek Field could return an additional 54 million stock tank barrels of oil above that recoverable by water flood, and may have wide application to similar Montana-Wyoming sandstone reservoirs.

CHAPTER III

GEOLOGY

A. Regional Geology

The Bell Creek Field is located in Southeastern Montana in Powder River and Carter Counties. The field is on the northeastern flank of the Powder River Basin.

The regional structure dips rather gently and uniformly to the west-northwest at approximately 100 ft. per mile, similar to that shown for Unit 'A', Fig. 6. Regional stratigraphic studies indicate that the Bell Creek area marks the site of intersection between northeast-trending offshore bars and a northwest-trending distributory system. The morphology of the reservoir sandstone suggests a barrier bar that is elongated to the northeast and parallel to the strike. Entrapment of oil occurred in sandstone bodies which pinch out to the southeast.

B. Bell Creek Muddy Sand Unit 'A'

The Bell Creek Muddy Sand Unit 'A' encompasses the most northern of the several Muddy reservoirs within the field area, Fig. 2. The reservoir is a stratigraphic

trap found in the Muddy Formation of Lower Cretaceous age. It is bounded on the west and northwest by an oil-water contact and on the southeastern or up-dip edge by a stratigraphic pinch out of permeable sands, Fig. 3.

The Muddy sandstone at Bell Creek consists of a very fine to fine grained quartzose sand which forms the major part of the reservoir rock. Varied amounts of siltstone and shale are present, both laterally to and interbedded with the sandstone. A petrographic study indicates that the Muddy sandstone in Unit 'A' is a relatively clean, moderately well-sorted, semi-consolidated, and quartz-rich sandstone. The clay and silt fractions present in the sandstone range from 5% to 17% (by weight). Kaolinite is the major clay mineral, with various amounts of illite and montmorillinite. Calcium carbonate and/or siderite is present either as discrete crystals, or more commonly as interstitial cement with very patchy distribution.

The Muddy sand at Bell Creek can be divided into two general intervals, Zone I and Zone II, such as is shown in the Type Log in Fig. 7. Zone II is the target zone for the micellar-polymer pilot test. The net oil sand isopach of Zone II is shown in Fig. 3. A fence diagram indicating the distribution of Zone II in the pilot area is shown in Fig. 8.

CHAPTER IV

RESERVOIR DESCRIPTION OF
MUDDY SAND UNIT 'A'

A. Formation and Rock Properties

The average formation and rock properties for Unit 'A' are tabulated in Table 1. The average net pay thickness is 11.9 feet and the average porosity is 26%. The average air permeability is 1,000 md and the average water flood residual oil saturation is 34%.

B. Fluid Properties

Surface and bottom hole samples from the Bell Creek pilot area and Unit 'A' reservoir wells were obtained during the first contract year for fluid property determination. Table 2 shows the oil viscosity and density of a bottom hole sample obtained from Well #12-11 (see Fig. 5). Table 3 shows the hydrocarbon analyses of oil samples from Well #6-14, and Table 4 shows its high temperature distillation results. Table 5 shows the oil viscosity of well-head samples from Unit 'A' in the neighborhood of the pilot area at 35, 110 and 150°F. There appears to be a slight decrease in oil viscosity from northeast to southwest across the pilot area. Table 6 shows the PVT

properties of bottom hole samples from Well #12-11, which is adjacent to the pilot area (see Fig. 5). Table 7 shows the reservoir fluid compositions of bottom hole samples from Wells #6-14, #12-3 and #12-11.

The chemical compositions of original brine, produced water and injection water are shown in Table 8. Since Madison water TDS is less than that in the formation brine, the average *in-situ* brine salinity is continuously decreasing. Based on these analyses, current *in-situ* brine salinity is likely in the range of 1,000 to 7,000 ppm of total dissolved solids.

A detailed description of the reservoir properties in the pilot demonstration area, which was developed under this contract, is given in Chapter X, Sections A, B, C and D.

CHAPTER V

PRODUCTION HISTORY

A. Primary Recovery

The Bell Creek Field was discovered on June 4, 1967. Unit 'A' Reservoir had three small gas caps up-structure and a water-oil contact along the northwestern boundary of the unit. Since none of the three contributed significant oil recovery energy, the oil was mainly produced by solution-gas drive. During primary recovery, the reservoir pressure was depleted from 1,190 psi to approximately 110 psi. The production history is shown in Fig. 9. The peak production occurred during the month of August 1968. The ultimate primary recovery was estimated to be 22 million STB, which is about 17% of the original oil in place, 122 million STB, Table 9.

B. Water Flood Recovery

Water injection into Unit 'A' Reservoir was commenced in August 1970, Fig. 9. The water flood pattern was essentially a line drive from northwest to southeast. Progression of the flood front is illustrated in Fig. 4.

The Madison Formation served as the source of the injection water. Recently, a portion of the produced water has been reinjected back into the producing formation.

The first response to water injection was observed in October 1970, Fig. 9. Oil production in Unit 'A' has been maintained at about 13,000 BPD since early 1972. Projections indicate that ultimate recovery by water flood is 36 million STB (not including primary recovery), which is approximately 29% of original oil in place, Table 9. As of July 1, 1977, approximately 70% of the anticipated water flood oil had been recovered, and the projected economic life of the water flood was about six years.

CHAPTER VI

SELECTION OF A TERTIARY RECOVERY PROCESS

The oil industry has developed an extensive list of potential enhanced oil recovery methods which have been tested in the laboratory and, to a lesser extent, in the field. No one technique has a universal application and each field has to be considered individually due to the high cost of enhanced oil recovery systems and due to uncertainties involved in recovering the tertiary oil.

Three enhanced oil recovery methods were considered for possible application in the Unit 'A' Reservoir:

1) micellar-polymer flooding, 2) *in-situ* combustion and 3) carbon dioxide flooding. Operating and economic characteristics of these processes were investigated and a comparative study was made with respect to the Unit 'A' Reservoir properties. *In-situ* combustion was ruled out because caloric equivalencies indicated that the oil properties of Unit 'A' crude may not sustain the propagation of a combustion front. Carbon dioxide flooding was considered not feasible due to problems involving 1) gravity segregation, 2) poor mobility control and 3) economic supply of sufficient quantities of carbon dioxide. All indications favored the micellar-polymer process.

Industry-wide micellar-polymer research has led to a listing of desired reservoir characteristics for successful micellar-polymer flooding. Table 10 compares the desired characteristics with those existing at the pilot site of the Unit 'A' Reservoir. As indicated by this comparison, Bell Creek Muddy Sand Unit 'A' is essentially ideal for the micellar-polymer flood recovery process, and thus may indicate an upper limit to be expected for micellar-polymer recoveries in field applications.

CHAPTER VII

PILOT SITE AND PATTERN SELECTION

IN MUDDY SAND UNIT 'A'

A. Site Selection Criteria

The pilot demonstration was selected based upon four criteria: 1) that the site possessed the preferred reservoir characteristics; 2) that it had a good primary and water flood recovery; 3) that it lay in a watered-out portion of the reservoir; and 4) that the pilot results could be readily applied to commercial scale expansion. The reason for the third criterion is the necessity to distinguish between the tertiary pilot flood production and that from the continuing and on-going water flood. That is, the pilot results should be interpretable without the necessity to account for severe interferences due to water flood fluid migration across the pilot pattern.

A comprehensive reservoir study of well logs and production data from the 350-acre drainage area in which the confined 40-acre pilot is enclosed, Fig. 5, was carried out in order to determine the reservoir properties, production history and production mechanisms of

the pilot neighborhood area. Figure 8 from this study shows a fence diagram which displays good continuity within the tertiary target pay zone (Zone II) in the pilot area. Also, examination of the water flood performance of each well in the northeast portion of the Unit 'A' reservoir and the results of a pressure pulse test, Fig. 10, substantiated the continuity of Zone II, which was anticipated as a result of the log data study.

Based on the extensive reservoir studies described above, the northeast end of Unit 'A' reservoir was selected for the pilot demonstration. The actual location of the 40-acre pilot area lies in the middle of the reservoir limits and not against either the southeast or northwest zero isopach barriers, Figs. 3 and 5.

B. Pattern Selection

Bell Creek Field was developed on 40-acre spacing. Therefore, for the pilot test, a confined regular 40-acre, five-spot pattern utilizing the existing well configuration was selected, Fig. 5, because it was considered to offer the best combination of interpretive advantages and overall economics. In addition, the flow behavior in an isolated regular five-spot is not overly dependent on the variables such as injector-to-producer

ratio and mobility ratio. Further, since the field is developed on 40-acre spacing, the results from a 40-acre pilot can be directly transferred to the decision regarding future field expansion should the pilot prove to be successful.

The 40-acre pilot pattern is confined in a 160-acre region bounded by Wells #1-15, #1-16, #6-13, #7-4, #7-5, #12-8, #12-7, and #12-2, Fig. 5. The production rate from these exterior wells can be used to contain and control the micellar-polymer flood within the confined area so that the pilot five-spot flow pattern is representative of a field-wide repeated pattern. These boundary wells also provide the ability to isolate the pilot portion of the reservoir from the on-going water flood, as necessary, for quantitative evaluation of tertiary oil recovery in the pilot. The slight offset of the actual locations of the newly drilled wells, MPP#1, 2, 3, and 4 from a true square pattern, Fig. 5, was due to terrain imposed constraints.

CHAPTER VIII

MICELLAR-POLYMER PROCESSES - OPTIMAL DESIGNS

A. Introduction

Basically two different concepts have been developed for using surfactants in enhanced oil recovery. In the first concept, a solution containing a selectively low concentration of surfactant soluble in water -- i.e., a water-external surfactant solution -- is injected into the reservoir in relatively large pore volumes (10 to 60%) for the purpose of reducing interfacial tension between oil and water, and thereby increasing oil recovery. In the second concept, a relatively smaller pore volume (3 to 20%) of oil-external surfactant solution with a relatively higher concentrated surfactant solution is injected into the reservoir for the purpose of miscibly displacing the tertiary oil. Laboratory and field tests to date are not conclusive on the optimal applicability of either process.

There is a plausible fundamental argument that since both interstitial oil and water must be mobilized by the tertiary recovery processes, there is an open

choice in the selection of the carrier base for the surfactant. If this is the case, the economic argument favors water as the surfactant carrier rather than oil. However, water-external systems do not have the inherent mobility match to the mobilized oil bank, neither do they apparently have as high a tolerance to the salinity of the reservoir brine as that of the oil-external systems. Thus, typically, complicated hydrocarbon compounds are added to the water-external surfactant solution to compensate for these deficiencies. Thus, the economics of the two systems approach each other.

In order to determine which design philosophy would lead to a better performing micellar-polymer system for the Bell Creek reservoir, Gary Operating Company elected to have two processes developed, one representing each design philosophy. For an oil-external system, the Uniflood (TM) process of Union Oil Company was chosen; for a water-external system, Atlantic Richfield was chosen to construct a process based upon the optimal salinity approach. Each system was optimized for the Bell Creek fluids and rock properties.

Hereinafter, the two designs will be referred to, for the purpose of labeling, as the "oil-external" design and the "water-external" design, respectively,

always keeping in mind that these designs as constructed and optimized were unique to the Bell Creek fluid and rock conditions.

The work to be described below tends to indicate that leaving aside the intricacies of the phase chemistry, which is still not totally understood, there appear to be two distinct but somewhat related major trade-offs between the oil-external and water-external designs: 1) in the oil-external design, the increased cost of the oil sulfonate carrier is traded as against the effectiveness of the oil carrier's mobility control properties, and 2) in the water-external design, the decreased displacement effectiveness of the sulfonate phase relationships with the addition of polymer to the water sulfonate carrier is traded as against the subsequent improvement in the water carrier's mobility control properties. Although optimized for the same Bell Creek pilot area rock and fluids, the oil-external and water-external designs turn out to be quite dissimilar in chemical composition and slug size as will be discussed below.

The most crucial question faced by a micellar-polymer enhanced oil recovery project is how to determine which micellar-polymer design (of the dozen or so currently available from chemical flood design groups) will produce an optimal recovery from a given reservoir. One approach

is to carry out pilot tests side-by-side, as in the Cities Service/DOE pilot demonstration (Ref. 1). However, reservoir field tests involve many unknowns and uncontrollable factors, such that side-by-side pilot results may not really be comparable.

Thus, the most cost-effective approach may be to develop a Selection Methodology based upon a series of standard laboratory experiments and reservoir numerical simulations, all of which are specifically tailored to the given reservoir rock and fluid properties. Using this Selection Methodology, the best candidate process may then be selected for a pilot test. The operator of the Bell Creek Pilot Demonstration Project elected to develop such a Selection Methodology, and this is discussed in detail in Chapter IX.

B. Oil-External System

For an oil-external system, the Uniflood (TM) process of Union Oil Company was chosen. Uniflood is a soluble oil-polymer solution flooding process which combines miscible and micellar flooding techniques with mobility control and is documented in the technical literature, Ref. 2.

The Uniflood process consists of the following steps:

- i) Injection of a slug of a preflush chemical solution. The preflush chemical solution is used to properly condition the reservoir chemistry so that other chemicals, subsequently injected, can perform their function more effectively.
- ii) Alternate injection of small slugs of soluble oil and fresh water. The expanded soluble oil slug is developed in the reservoir by the cumulative effects of the alternate injection of a substantially anhydrous soluble oil and fresh water (designated "micellar" water). Since the function of the soluble oil slug is to miscibly displace the reservoir oil, the composition of the soluble oil is designed to give:
 - (a) The best possible phase relationship with the crude oil and the micellar water, Fig. 11. (To assure optimization of the interfacial phase chemistry, the distribution of hydrocarbons in the Bell Creek crude may have to be modified slightly, since it is deficient in light ends, Table 7. The crude oil in the Ternary Phase Diagrams, Figs. 11, 13 and 14, are all composed of such modified crude.)

(b) Appropriate viscosities for the micellar slug in order to provide a favorable mobility ratio with the oil bank developed ahead of the soluble oil slug.

iii) Injection of a large slug of polymer solution.

The aqueous tapered polymer solution drives the soluble oil slug through the reservoir.

The polymer solution must maintain the favorable mobility ratio with the soluble oil slug and with the oil bank developed ahead of the soluble oil.

iv) Injection of fresh (<1% salinity) water. Injection of this water is continued until about 1.5

pore volume of total fluids have been injected.

Some portion of this water may contain small (<100 ppm) amounts of polymer, as required.

The Uniflood process is designed to give miscible

displacement over as much of the flood path length as

possible and immiscible (low interfacial tension)

displacement for the remaining portion of the flood

path.

The following factors are considered in the design

of the Uniflood Process:

i) Reservoir oil - composition, viscosity,

saturation in reservoir rock.

- ii) Reservoir brine - salinity, hardness, divalent cations, pH.
- iii) Reservoir rock - porosity, permeability, heterogeneity, composition, clay type, divalent cation content, ion exchange capacity.
- iv) Other - adsorption of chemicals, fluid mobilities, ionic strengths of fluids, well spacing and configuration, well conditions, reservoir temperature and pressure.

1. Phase Relationships

The ternary phase relationships between the crude oil, the sulfonate-solvent and the micellar water used in the make-up of the soluble oil slug for a micellar flood indicate the efficiency to be expected from the flood. Under conditions which result in only a small, two-phase area in the phase diagram, Fig. 11, only small amounts of sulfonate-solvent are required to obtain single phase brine mixtures. Also, as noted on Fig. 11, the composition of the slug of micellar solution developed in the oil-external Uniflood process remains as a single phase even after a high dilution by the water phase (dotted line). This permits miscible type oil recovery to be maintained throughout a large portion of the flood. The viscosity of the soluble oil slug, Fig. 12,

under various dilution conditions which occur in the reservoir, is relatively constant at levels required for adequate mobility control of the flood.

Two other phase diagrams were determined in this study; one in which large amounts of Ca^{++} (250 mg/l) were added to the micellar water, Fig. 13, and the other in which polymer (950 ppm) was added, Fig. 14. In both cases, a much larger two phase area was noted. The presence of either material increases the interfacial tensions between the oil and the brine phases.

2. Preflush

A patented high pH silicate preflush system is used in the Uniflood process to efficiently remove multivalent cations (Ca^{++} , Mg^{++} , Fe^{++}) from areas which will be invaded by subsequently injected surfactants and polymers. The preflush used in this process accomplishes this both by displacing the resident brine and by ion exchanging with reservoir rock. It also tends to inactivate clays by removing bound water in clays. It tends to make reservoir rock water-wet, and it provides a favorable salinity and pH for the surfactant and polymer slugs when they later invade the preflushed area. In some cases, the preflush increases the volume of reservoir contacted by

the surfactant and polymer slugs. Other processes employ NaCl, Na₂CO₃, and/or similar salts which may be less efficient preflush solutions.

3. Soluble Oil Slug

The oil-external slug used in the Uniflood process has a viscosity sufficiently high to create a favorable mobility ratio between it and the oil bank which it mobilizes in the reservoir. By contrast, aqueous surfactant processes usually rely upon polymer or special surfactants added to the slug in order to attain the proper viscosity. However, the presence of polymer in a micellar slug has the negative effect of decreasing its oil recovery efficiency.

In the soluble oil slug, the surfactants are essentially completely soluble in the carrier oil. The soluble oil is miscible with the resident oil regardless of the salinity of the brine associated with that oil. Resident brine containing divalent salts will not precipitate the surfactants from these soluble oils.

A primary goal in tertiary oil recovery is the formation of a flowing oil bank in a reservoir which has been subjected to a water flood down to

the immobile residual oil saturation. Soluble oil, being an oil phase, achieves this mobilization goal immediately upon commencement of the soluble oil flood. By contrast, aqueous surfactant solutions must build an oil bank from the immobile oil.

The surfactant and stabilizer in the soluble oils are chosen to provide the most favorable phase relationships between crude oil and the water used to drive the bank through the reservoir, Fig. 11. The selection of the type of oil used in the micellar system provides a degree of flexibility in obtaining the most favorable phase relationships (and, as a result, the most efficient oil displacement) for the oil-external process. This flexibility is particularly important in the design for the Unit 'A' reservoir because of the unusual composition of the crude oil in the light ends, Table 7, as mentioned above. In formulating the soluble oil, there is the flexibility to incorporate either the reservoir oil, an adjacent reservoir oil, a refinery hydrocarbon product such as a gas-oil, or a combination of these. The cost of the oil in the soluble oil slug represents less than 10% of the chemical cost of applying the oil-external Uniflood process.

One advantage of the high concentration oil-external process is that it uses a small slug which, to a large extent, maintains its integrity in the reservoir. Laboratory core and computer model studies have shown that these small slugs have high concentrations of surfactants which can be diluted in the reservoir (and expanded in size) to as low as about 1% active surfactant and still be very effective. The high concentration slug displaces oil very efficiently as a miscible slug through a portion of the reservoir. Then, through dispersion, the injected slug grows in size in the reservoir and eventually becomes about equivalent in displacement efficiency to a large slug of low concentration micellar solution.

4. Polymer Slug

The polymer solution used to drive the soluble oil slug and oil bank through the reservoir is formulated with polyacrylamide. It does not invade the soluble oil slug to the point of damaging its effectiveness. This is partly because of the flow characteristics of the polymer solution and partly because the polymer is insoluble in oil. As a result, the micellar slug is not deteriorated by

polymer invasion to any appreciable extent. An invasion of the micellar slug by the drive polymer can cause the phase relationships between oil, surfactant and polymer water to be less favorable than if the polymer was not present (compare Fig. 14 with Fig. 11).

Both liquid emulsion polymers -- Nalco and Cyanamid -- and dry polymers -- Dow and Calgon -- were tested in the Bell Creek Uniflood design and were found to be satisfactory from a performance point of view.

5. Optimal Oil-External Process

Based on the results of the Bell Creek design experiments and an extensive background of other laboratory field work, the oil-external design for the pilot flood and ultimate full scale application in Bell Creek Unit 'A' reservoir consists of the following sequence of fluid injections (see also Table 11):

- (1) A 10% pore volume slug of a high pH silicate solution;
- (2) A 3% pore volume slug of micellar solution (7.6 volume % active sulfonate-solvent) consisting of about equal amounts of soluble oil and water injected alternately in small slugs;

- (3) A 60% pore volume slug of a graded, aqueous polyacrylamide solution;
- (4) Approximately 70% pore volume of drive water.

C. Water-External System

The water-external process is also a slug process which includes a sequential injection of a preflush, a slug of water-external micellar solution, a slug of polymer mobility control solution, and finally a drive water. The water-external micellar system relies on the attainment of ultra-low interfacial tension for recovering tertiary oil. The success of this process depends critically upon designing a micellar slug which is interfacially active in the presence of reservoir oil and brine at or near the reservoir salinity.

The Atlantic Richfield Company philosophy for the design of an optimal water-external process followed these criteria:

- i) A water-external micellar injection fluid with no hydrocarbon added;
- ii) A specified phase behavior at a constant salinity;
- iii) An optimal salinity within the range of expected *in-situ* salinities (1,000 to 7,000 ppm TDS).

1. Surfactant-Alcohol Screening

Thirty surfactants and six alcohol cosolvents were screened in order to select a formulation of a water-external micellar solution for final laboratory testing. Surfactants were screened by using phase behavior tests to find the optimal salinity of each surfactant when mixed with a fixed weight percent of a cosolvent, normal amyl alcohol, Figs. 15 and 16. Formulations with an optimal salinity within the design criteria and with encouragingly low interfacial tension at the optimal salinity were tested in a 4' Berea core. Formulations with encouragingly low IFT's and with optimal salinity close to, but outside of, the desired range were reformulated with different alcohols. If the reformulated solutions had an optimal salinity within the desired range, low IFT's at the optimal salinity, and a good phase stability for injection, then these also were tested in 4' Berea core floods.

2. Water-External Micellar Solutions

Primary micellar solutions from the surfactant screening studies were tested for oil displacement effectiveness in 4' Berea cores. The cores were

first driven to connate water saturation, and then were water flooded to residual oil saturation before chemicals were injected. Micellar flooding tests were conducted at approximately one foot per day frontal advance velocity. In these tests, standard 10% PV micellar solution slugs containing 4 weight percent active surfactant were displaced by continuous injection of 1,500 or 2,000 ppm solution of polysaccharide polymer. Table 12 shows the variations in recoveries for different distributions of micellar-polymer concentration variables.

From this preliminary screening of surfactants and alcohols, Stepan Petrostep 465 petroleum sulfonate and normal amyl alcohol were selected as the surfactant and alcohol for final design optimization, Fig. 16.

Variations in the salinity, surfactant concentration, alcohol concentration and polymer concentration of the micellar solution were examined. Figures 17 and 18 show how final oil saturation varied with the salinity and polymer concentrations. Although the optimal salinity as defined by interfacial tension measurement was approximately 6,000 ppm TDS, Fig. 16, the lowest final oil saturation was obtained at a salinity of 3,000 ppm TDS, Fig. 17.

Surfactant concentration in the water-external micellar solution was tested at two levels, 2 and 4 weight percent of the fully active material in the respective slug pore volume. In the case of a 20 PV - wt % surfactant slug injected (10% PV x 2% wt active or 5% PV x 4% wt active), the 2% weight active concentration was more effective, resulting in a final post-chemical flood oil saturation which was 3.5% PV lower than that given by the 4% solution. However, the 4% weight active solution was more effective when the total surfactant slug injected was 40 PV-wt%, resulting in a final post-chemical flood oil saturation which was 1.9% lower than that given by the 2% solution. Little effect of alcohol concentration on oil displacement was found over the range of 0.77 - 1.28 weight percent.

3. Preflush Solution

Several preflush compositions were evaluated in an original screening test for consumption of the sacrificial agent and the ability of the agent to reduce surfactant adsorption. Two compositions were tested for overall effectiveness in core flooding. However, a preflush solution was not

found for the water-external design that was effective in displacing adsorbed divalent ions or in suppressing these ions sacrificially, and which was also practical economic to use. Thus, a preflush of NaCl or other inorganic salt was chosen.

4. Polymer Drive

Two polyacrylamide polymers, Dow Pusher 700 and American Cyanamid Cyanatrol WF 950S, were examined for sensitivity to salinity (and calcium ion), shear degradation at high injection rates, chemical stability, and injectivity into sandstones.

Injectivity tests were conducted with two polysaccharide polymers, Kelco Xanflood and Pfizer 1035. Chemical stability tests were made only for Xanflood. The polysaccharides were ultimately eliminated from further design considerations because of poor injectivity, potentially limited chemical stability, and cost.

Based on laboratory test results, the Cyanatrol WF 950S was chosen for the final design formulation. Using Cyanatrol WF 950S, the following polymer drive variables were examined in displacement tests: polymer concentration, salinity contrast with the micellar slug, and polymer slug size. As would be expected, increasing the polymer concentration resulted in a

lower final oil saturation since the mobility ratio became more favorable, Fig. 18. Above 1,500 ppm further increases in polymer concentration caused only slight reductions in final oil saturation.

Results of the salinity contrast tests indicated that it is important to have a polymer drive salinity compatible with the micellar solution salinity. A polymer slug size of 60% PV appears to be adequate and gives essentially the same results as that of continuous polymer injection.

5. Optimal Water-External Process

From the above work, the following optimal water-external process for the Bell Creek pilot flood in Unit 'A' and ultimate full-scale applications was proposed (see also Table 11):

- (1) A 40% pore volume slug of preflush of NaCl or other inorganic salt;
- (2) A 12% pore volume slug of 2.77% weight active sulfonate-alcohol;
- (3) A 60% pore volume slug of polyacrylamide graded polymer solution (1,200 ppm average).

All of the slugs are at the optimal salinity of 3,500 ppm TDS.

CHAPTER IX

MICELLAR-POLYMER PROCESSES --

SELECTION METHODOLOGY AND EVALUATION

A. Introduction

Although optimized for the same Bell Creek pilot area rock and fluids, the resulting oil-external and water-external systems were quite dissimilar in chemical composition and slug size, Chapter VIII, Table 11.

This chapter addresses the most crucial question faced by a micellar-polymer project: how to determine which micellar-polymer design will produce maximum recovery performance in a given reservoir. One approach is to carry out pilot tests side-by-side (Ref. 1). However, reservoir field tests involve many unknowns and uncontrollable factors; and therefore side-by-side pilots may not be really comparable.

Thus, the most cost-effective approach may be to develop a Selection Methodology based upon a series of standard laboratory experiments and reservoir numerical simulations, all of which are specifically tailored to

the given reservoir rock and fluid properties; then from such comparable laboratory data to select the best candidate process from among the system designs offered; this selected design then to be subjected to a pilot test. The operator of the Bell Creek Pilot Demonstration Project elected to develop such a Selection Methodology.

B. Selection Methodology

The Selection Methodology is built of the following components:

Component I

Standard Laboratory Core Tests, Bell Creek Pilot Area Fluids.

A. Standard Berea Cores, 4 feet long

B. Bell Creek Pilot Area Cores, 12 inches long

Component II

Independent numerical simulation of laboratory core tests. Critical inputs to be obtained independently from and/or checked against laboratory test results.

The phase diagram, viscosities and interfacial tensions are obtained independently.

Component III

Numerical simulation of pilot and composite field five-spot performances. Critical inputs to be

obtained independently from or checked against laboratory and field experimental results.

The primary tool for the evaluation of the recovery performance between the two competing micellar-polymer system designs is the Standard Laboratory Core Tests with Bell Creek fluids -- brine and crude oil. The purpose of Component IA, "Standard Berea Cores", is to give a comparison of the two micellar-polymer systems in as nearly a controlled standard experimental environment as possible. The Berea cores were cut from the same piece of quarry rock. Component IB, "Bell Creek Pilot Area Cores", sacrifices some degree of standardization between the tests of the two designs (since no piece of reservoir rock is identical to any other piece); but, in turn, attempts to include the parameters of the actual reservoir rock, which are essential to a meaningful evaluation of the two processes. The Bell Creek core plugs used in Component IB were cut from the same well core, MPP-5.

The purpose of Component II, "Independent Numerical Simulation of Laboratory Core Tests", is to assure that there is a reasonable understanding of how the particular micellar-polymer design works. Without such understanding, the rational basis for choosing a particular design based upon laboratory results is severely limited. The purpose

of the numerical simulation is to connect the laboratory results with the likely field recovery performance, Fig. 19. The simulators used in the DOE/Bell Creek Pilot Project are the Larson/GOC one-dimensional CHMFLD program, Appendix II, and the Intercomp Chemical Flood Simulator (CFS), Refs. 3 and 4. This Intercomp CFS is one in which the areal fluid dynamics and the micellar-polymer phase chemistry are fully coupled.

Component III, "Numerical Simulation of Pilot and Field Performance", has two purposes: A) to include in the evaluation of the recovery performance of the two chemical designs the effects of reservoir heterogeneities, dispersion, and slug size threshold effectiveness over large distances -- variables which cannot be properly modeled in the laboratory due to the countervailing scaling requirements; and B) to provide a technique for comparing the economics of the two processes with respect to the cost of chemicals injected versus the value of the oil recovered as a function of time in a field five-spot pattern.

There are four primary criteria by which to compare micellar-polymer systems designs:

- Oil displacement efficiency at the optimal design condition
- Sensitivity of oil displacement efficiency to off-design conditions
- Areal sweep efficiency
- Economic cost of injection (chemicals, fluids, logistics and facilities)

Superiority as used in the Selection Algorithm given below is meant to include these four criteria as relevant and appropriate.

C. Selection Algorithm

The Selection Algorithm involves the following cases with optimal chemical design formulations A and B; see Table 13.

Case I: Highest Order Case

Core Flood A equal to or superior to Core Flood B.
 Simulator predicts core flood results for A & B.
 Simulator predicts pilot/composite field results:
 A superior to B.
 Choose A.

Case II: Simulator Field/Core Reversal

Core Flood A superior to Core Flood B.
 Simulator predicts core flood results for A & B.
 Simulator predicts pilot/composite field results:
 B superior to A.

If reversal in superiority is understood, choose B, simulator result.

If reversal is not understood, choose A, core flood result.

Case III: Simulator Fails Prediction Capability, Both Designs A and B

Core Flood A superior to Core Flood B.

Choose A.

Case IV: Simulator Fails Prediction Capability, Design B Only

Core Flood A superior to Core Flood B.

Simulator predicts core flood results for A, fails B.

Choose A, core result.

Case V: Simulator Fails Prediction Capability, Design A Only

Core Flood A superior to Core Flood B.

Simulator predicts core flood results for B, fails for A; indicates an understanding of Design B, but not of A.

A matter of technical judgment: choose, on basis of information in hand, or elect to do additional work to gain more detailed understanding of Design A.

Case VI: Core Flood and Simulation Results Essentially
Equal

A matter of technical judgment: choose, or elect to do additional work to gain more detailed understanding of Designs A and B.

The Selection Algorithm as presented above does not include the sub-routine which would be required if there is a superiority reversal in displacement efficiencies between the results of Component IA, Standard Berea cores and Component IB, Bell Creek Pilot Area cores. The reason we do not consider this sub-routine here is that industry experience with core-flooding of reservoir rock indicates the qualitative nature of the results obtained. The linear laboratory reservoir test cores must be constructed from a set of sequential segments of small length plugs taken from well cores. If the attempt is made: 1) to preserve the native state of the well core plugs with return to S_{Or} by means of a flood with reservoir crude followed by a flood with reservoir brine, the question arises as to how well the conditions in the restored plug represent the *in-situ* reservoir conditions; or 2) to extract the well core plugs and then restore to S_{Or} , the same question arises. Further, with a laboratory test core constructed of

several well core plug segments butted together, the question of multiple internal end effects also arises. In the case of radial cores, the radial flow length is also severely restricted.

Thus, the selection philosophy in the Bell Creek Pilot project was to use the Bell Creek Pilot Area Core Tests, Component IB, only to indicate the extent to which the performance of the given micellar-polymer design might be enhanced or degraded in the reservoir rock environment *vis-à-vis* that in Berea rock, Component IA, and to gain an understanding of the operative mechanism causing this change in process performance.

D. Component I -- Standard Laboratory Test Series*

The Standard Laboratory Core Tests, Component IA of the Selection Methodology, consist of the following three test categories:

1. Optimal Design in Berea Rock
 - A. Optimal Design Preflush, Micellar and Polymer Slug Sizes, Table 11
 - B. Optimal Design Preflush; Micellar and Polymer Slugs, Sized 1 PV each.
2. Ruggedness of Design in Berea Rock
 - A. Fractional Micellar Slug Size

*The draft of this Section was prepared by Dr. J. J. Rathmell of Atlantic Richfield Company. Subsequently, it became the combined work of all of the principal investigators referred to in the Acknowledgment.

B. Maximum Divalent Ion Concentration

3. Optimal Design in Bell Creek Pilot Area Rock

In each core test, the core is set up with reservoir fluids so as to best represent the condition in the pilot area reservoir. The flooding rate is maintained near the expected average reservoir rate of one foot per day.

Test 1A: Optimal Process Design in Berea Rock. In a 4 foot long Berea core having a K_a near to the reservoir K_a , conduct an oil displacement test using the optimal process design. This is a standard slug displacement test. All slug sizes, slug compositions, and other displacement variables are to be, as nearly as possible, representative of the pilot test area variables (see subsection, "Rock and Fluids", below). Recognition must be made of the fact that certain differences between Berea and the reservoir rock may require adjustment of some process variables or techniques to give representative slug performance; for example, polymer slug viscosities may require alteration because of the difference between the relative permeabilities in Berea and Bell Creek rock. Repeat this standard slug displacement test to demonstrate reproducibility of the test results.

Test 1B: Optimal Process Design in Berea Rock, Micellar and Polymer Slugs Sized 1 PV Each. The primary purpose of this test is to provide data for the Chemical

Flood Simulators on the distinct physical chemistry characteristics of each process at the front and the back of the respective micellar slug. The actual test results will also indicate to the observer how well each slug part, micellar and polymer, is achieving its purpose -- oil displacement and oil bank mobility control, respectively.

Test 2A: Ruggedness of Design to Fractional Slug Sizes. Repeat Test 1A with micellar fluid slugs of smaller size than the optimal process design. The purpose of Test 2A is to determine the effect of reduced slug size on the performance of the process. In a five-spot configuration, only one of the stream tubes (slightly off the diagonal from injector to producer) will receive the "optimal" process design. The stream tubes further removed from the diagonal stream tube will receive succeedinglly smaller micellar slug sizes relative to the total pore volume of the respective stream tubes. Thus, total process performance will depend upon how well the process works at succeedinglly proportionally smaller slug sizes.

Test 2B: Ruggedness of Design to Divalent Ions. Repeat Test 1A, except that the core is equilibrated using reservoir brine containing the maximum calcium/

magnesium ion concentrations expected to be encountered in the Bell Creek Field reservoir, i.e. 250 mg/l Ca^{++} , Table 8. The purpose of this test is to determine the sensitivity of the optimal process design to the worst case divalent ion and salinity concentrations.

Test 3. Optimal Process Design in Bell Creek Pilot Area Rock. Repeat Test 1A using sections of Bell Creek Muddy Sandstone core plugs butted together to form a core approximately 12 inches long by 1-1/2 to 2 inches in diameter. The purpose here is to demonstrate the effectiveness of the optimal process design in conditions as close to the *in-situ* reservoir conditions as possible. Repeat this standard slug displacement test to indicate the reproducibility of the test results.

Rock and Fluid Properties: The Berea sandstone cores for the Standard Laboratory Test Series 1 and 2 were cut from the same Berea block at Cleveland Quarries. The Bell Creek Muddy Sandstone plugs for Test Series 3 were obtained in the following way. The well core from MPP #5 had 2-inch long x 2-inch diameter horizontal plugs taken from the top to the bottom of the net pay. Each plug was subjected to treatment with Bell Creek stock tank oil to reduce the plugs to connate water saturation, S_{cw} .

Permeability to oil, k_o , was measured for each plug at S_{cw} . The plugs were then sequentially ordered from k_o maximum to k_o minimum. By flip of coin, the first plug was assigned to one of the two design groups, and then every other plug in order of decreasing permeability was assigned alternately. To the extent that additional plugs were required to make up the 12-inch long laboratory test cores to fulfill Test 3, these were obtained from pilot area cores from wells MPP #1-#4.

Reservoir brine was constructed by matching as closely as possible the average of produced water from the producing wells nearest to the pilot area, Table 8. Reservoir oil was constructed from stock tank oil plus solution gas such as to make a reservoir oil composition as close as possible to the average of the analyses of the bottom hole samples from pilot area wells #6-14 and #12-11, Table 7.

E. Results: Standard Laboratory Test Series

The recovery efficiency results for the Standard Laboratory Core Tests 1A, 2A and 2B in Berea rock are shown in Table 14 and Fig. 20. It is seen that the oil-external design is superior. Analysis of the results of Test 1B, the "Long Slug" experiment, tends to indicate that the oil-external design has better

displacement efficiency and mobility control than the sister water-external design. Also, the Test 2B results tend to indicate that the oil-external design provides better protection of the micellar phase chemistry against divalent ion attack, Table 14.

Relative one-dimensional economics can be derived from the data of Fig. 20, and these are shown in Fig. 21, with results normalized to a reservoir $S_{Or} = 30\%$ and tertiary oil valued at \$13.50 per barrel.

The recovery efficiency results for the Standard Laboratory Core Tests 3 in Bell Creek rock are shown in Fig. 22. These results show a serious degradation in process performance from the results obtained in Berea, Fig. 20. Explanations advanced for this deficiency are: shortness of the Bell Creek Reservoir laboratory test cores (6" to 12" long) relative to the Berea cores (4' long); multiple end effects due to the sequenced core plugs (2" long) which were loosely butted, due to the friability of the Bell Creek rock; moving fines; and possibly the mis-design of the optimal processes with respect to mobility control for the Bell Creek sandstone reservoir conditions. It is interesting to note that the relative performance of the two processes remains approximately the same as in Berea rock; compare Figs. 22 and 20. However, as indicated in the discussion on Component IB (above) in the "Selection Algorithm"

section, work will proceed to gain a specific understanding of the operative mechanisms which are causing this reduction in process performance.*

F. Components II and III -- Numerical Simulation

Following the logic of the Selection Methodology, Fig. 19, numerical simulation was used to connect the laboratory results with pilot/field predictions. The phase chemistry for each process was determined with the one-dimensional CHMFLD programs, Appendix II.

Final simulation work was accomplished using the Intercomp Chemical Flood Simulator, a finite difference method, implicit in pressure only. The CFS model solves for six components (or species) in two fluid phases, Ref. 4. All six components may partition between the aqueous and hydrocarbon phases. Mass transfer is assumed to be sufficiently fast compared to fluid flow that chemical equilibrium exists across all phase boundaries. Four components may disperse by both molecular diffusion and mechanical dispersion in both the longitudinal and transverse directions and in both phases. The same four components may adsorb on the reservoir rock, satisfying equilibrium adsorption isotherms. An inaccessible pore volume may be specified for one of the components. The model allows for a one-

*Work subsequent to this reporting period indicates that the apparent degradation is due to the decrease in oil recovery with decreasing permeability, the Bell Creek core plugs being of low permeability (water at residual oil) than the Berea cores.

dimensional, variable width grid , a two-dimensional vertical, variable width cross-sectional grid; and a two-dimensional areal grid geometry.

Using the laboratory physico-chemical data obtained for each process (i.e., phase diagrams, interfacial tensions, viscosities, etc. -- see Table 15 for input requirements), and history matching to the one-dimensional core experiments for dispersion, adsorption and low tension k_r , an internally, self-consistent set of simulator input was obtained for each micellar-polymer process -- oil-external and water-external respectively.

The simulators require for each process the common inputs of the relative permeabilities and the capillary number correlation. These were determined in the following way. A set of Berea core relative permeabilities, Fig. 23, were measured (unsteady-state) at the Union Oil Company Laboratory using Bell Creek fluids at low rate - low values of capillary number, $K(\Delta p/\Delta x)/\sigma$. The Berea core used in the relative permeability measurement was not one from the common lot of cores used in the Standard Laboratory Test Series. However, before each of the Standard Core floods, the oil relative permeability at connate water saturation and the water relative permeability at residual oil saturation were measured. These data points, though varying amongst themselves by 10-20%,

were in reasonable agreement with the experimental end points of the relative permeability curves of Fig. 23. The value of S_{or} determined before each flood was nearly invariant, and agreed with that of the relative permeability measurement to within 1 or 2 saturation percent.

In addition to the ordinary high interfacial tension, low capillary number curves, the simulator requires as basic input a set of low tension curves, applicable at high capillary number. As a first approximation, the low tension relative permeabilities reported by Talash, Ref. 5, linearly adjusted to the connate water of Fig. 23, were used. Then the low tension water curve was adjusted by history match to the water-external process results to obtain the curves shown in Fig. 23.

It was found that the simulation of the oil-external process was not particularly sensitive to the choice of these curves, so long as the low tension residual oil saturation was zero. The simulation of the water-external process, however, was very sensitive to this choice. Thus, two low tension water curves were used as required by history match. This difference in sensitivity between the two processes is due to the fact that with surfactant present, the aqueous phase in the oil-external process has high viscosity, even in the absence of polymer; whereas in the water-

external process, the aqueous phase has, in the absence of polymer, a relatively low viscosity.

For the capillary number correlation, the careful work in Berea rock of Taber, Ref. 6, and McMillen and Foster, Ref. 7, was used, Fig. 24. If two phases are flowing the appropriate correlating group is $N_{ca} = k(dp/dx)/\sigma$.

In the simulator, relative permeabilities as a function of N_{ca} were obtained by an essentially linear interpolation between the low and high tension curves using the S_{orc}/S_{orw} as a function of N_{ca} as the interpolant, where S_{orc} is S_o residual after chemical flood and S_{orw} is S_o after water flood.

G. Results: Numerical Simulation of Standard Laboratory Test Series

Using the simulator input as indicated above, the simulated and experimental recovery curves for the optimal oil-external and water-external designs, respectively, are shown in Figs. 25 and 26. In Fig. 26, two experimental cumulative oil recovery curves are indicated by the squares. These data correspond to two separate experiments run in the same manner. The difference between the two curves is an indication of the lack of exact experimental

reproducibility due to deviations among cores and to measurement error. On the whole, the simulated oil recovery is within the reproducibility error. Note that the shape of the simulated surfactant effluent concentration curves agree with the experimental data. The agreement in area under the curves indicates correct simulation of the adsorption level for each process. The agreement in peak height indicates that the dispersive mixing length ($\alpha = 0.05$ feet) has been chosen correctly. The simulated surfactant effluent curves, however, are generally shifted to the right relative to the experimental curves. Thus, interaction of surfactant and polymer may still not have been correctly modeled.

Varying only the input slug size, the core flood production histories of oil and surfactant were successfully simulated for the complete suite of fractional sized (1, 3/4, and 1/2) core floods for each respective design, Ref. 4. The numerical simulation results for the cumulative oil recoveries in Berea cores are displayed, along with experimental data, in Fig. 27. The agreement is excellent.

H. Results: Numerical Simulation of Pilot/Field Performance

To estimate the effect of areal sweep on pilot performance, the simulator was run in a two-dimensional

areal mode for each process, using the physico-chemical input data for the Berea core floods described earlier. Uniform field properties were assumed: a permeability of 1,050 md, the average for the Bell Creek pilot area, and a uniform water flood residual saturation of 0.35, see Chapter X.

The equations were solved on the minimum element of symmetry, an eighth of a five-spot. For the areal simulation, a Péclet number (Np_e) of 80 was chosen, the same value of Np_e as was used in simulating the core floods. This corresponds to $\alpha = 12.5$ feet for the field -- a value much higher than that in the cores and therefore modeling to some extent the heterogeneities to be expected in the field. With this level of physical dispersion, the use of 30 grid blocks along the streamline direction and four perpendicular to it appear to be sufficient to dampen out numerical dispersion.

The results of the areal simulation are shown for the oil-external and water-external design respectively in Figs. 28 and 29.

To investigate potential vertical conformance difficulties in the Bell Creek field, the oil-external and water-external processes were simulated with a

two-dimensional vertical cross-section grid. The input variables to this simulation included uniform Berea properties, $S_{or} = 0.35$, Bell Creek pilot average horizontal permeability, $K = 1,050$ md, and an average pay zone thickness of 8.1 feet, Figs. 39 and 40.

The effect of layering, which could be important in the pilot, was not simulated, but gravity segregation was modeled. Bell Creek water and oil densities of 64 lb/ft^3 and 54 lb/ft^3 at reservoir pressure were input to the simulator. Rock and fluid compressibilities were taken to be $3 \times 10^{-6} (\text{psi})^{-1}$ and $10^{-6} (\text{psi})^{-1}$. Capillary pressure was obtained from a capillary drainage curve measured on a Bell Creek pilot area core. The ratio of vertical to horizontal permeability was graded from 0.2 at the top of the pay zone to 0.1 at the bottom. These values represent a somewhat smaller vertical to horizontal ratio than indicated by the plug core data in Tables 18 - 22. However, the effect of shale streaks which are typical of barrier bar deposits would have the effect of decreasing the plug core data ratios to the macroscopic values indicated here.

Thirty longitudinal blocks and four vertical blocks were used in the simulation. Variable block

widths were employed to capture some of the effect of diverging flow. The widths chosen were calculated from the widths appropriate for a second-from-the-center streamtube of an eight equal-flow streamtube description of a quarter five-spot with unit mobility ratio flow.

In the vertical simulation of the water-external design, by the time the .12 PV surfactant slug had been injected, significant gravity overriding of oil had occurred. Thus, the oil soluble surfactant was carried toward the top, while the water soluble surfactant drifted to the bottom of the formation. The oil soluble surfactant, being the more surface-active, was more effective in sweeping oil and thus residual oil was left at the producing end predominantly at the formation bottom, contrary to what one ordinarily expects of the more buoyant fluid. In point of fact, this is in agreement with the experimental water-external core floods, where examination showed that residual oil at the end of the cores was found at the bottom of the cores.

In the oil-external vertical simulation, the short, 0.03 PV, viscous neutrally buoyant soluble oil slug was quickly followed by viscous polymer, thus obviating the tendency of the brine to underrun. The

brine solubility of the oil-external surfactant resulted in better sweep of the bottom layers, residual oil being left at the top. Overall, oil-external vertical sweep efficiency was numerically predicted to be 85% compared to 68% in the water-external case.

Thus, having established confidence in the simulator mechanics and the physico-chemical inputs, Section IX.G, the simulator was then used in a pilot/field predictive mode, for pilot scale, two-dimensional areal simulations. These results were then used to fashion economic comparisons based on "Present Value Cash Flow After Tax". These economic predictions, Fig. 30, confirmed the conclusion indicated by the core floods reported in Component I that the oil-external design appears to be the more promising for application at Bell Creek.

I. Conclusion: Application of Selection Methodology

The optimal oil-external and water-external micellar-polymer designs for the Bell Creek Pilot Demonstration, Table 11, were each carried through the Selection Methodology: Components I, II and III, Fig. 19. In terms of the Selection Algorithm,

the results correspond to Case I, Table 13, with the oil-external process being the more promising of the two designs for the Bell Creek pilot application.

The results of the Standard Laboratory Test Series and the Numerical Simulation work appear to indicate that the superiority of the oil-external process is due to its more effective displacement efficiency, mobility control and protection against divalent ions. Special note should also be taken of the effectiveness of the high pH silicate preflush in reducing adsorption and removing harmful divalent ions.

CHAPTER X

FIELD ENGINEERING PROGRAMS

A. Pilot Well Development

1. Existing Wells and Completion

The existing wells in the confined pilot demonstration area include Wells #1-15, #1-16, #6-13, #7-4, #7-5, #12-1, #12-2, #12-7 and #12-8, Fig. 5. The completion data for these wells are tabulated in Table 16. A typical existing well completion is shown in Fig. 31. They were completed with a 5-1/2" casing which was cemented with 150 sacks and perforated across the pay sand interval with four jet shots per foot.

2. New Wells and Completion

New wells drilled in the pilot area are Wells #MPP-1, #MPP-2, #MPP-3, #MPP-4 and #MPP-5. Wells #MPP-1, #MPP-2, #MPP-3 and #MPP-4 are going to be used as injectors. Well #MPP-5 will be used as an observation well. The completion data for these wells is tabulated in Table 17. Figure 32 shows the typical new well completion for fluid injection wells. They

were completed with a slotted liner across the pay, which liners have open areas approximately equal to 14% of the total sand face area in the pay zone. This design was used to insure that the estimated shear rate during injection would be less than $16,000 \text{ (sec)}^{-1}$. Below this value, the estimated shear degradation should be less than 10% for the expected Ca/Mg divalent ion concentration in softened Madison water.

3. Core Analyses and Well Logs from New Wells

Core analysis results from Wells #MPP-1, #MPP-2, #MPP-3, #MPP-4 and #MPP-5 are shown in Tables 18, 19, 20, 21 and 22 respectively. The average porosity and air permeability of these core analyses are tabulated in Table 23.

Neutron and density porosity logs taken from Wells #MPP-1, #MPP-2, #MPP-3, #MPP-4 and #MPP-5 are shown in Figs. 33, 34, 35, 36 and 37 respectively. The log suite for these wells included dual latero-log with microspherically focused log, bottom hole compensated sonic log, compensated neutron log, and compensated formation density log, except for Well #MPP-3 which has an additional dual induction log, Table 24. An analysis of all the log and core data

available on wells in the 160-acre study area results in the thickness, porosity and permeability data reported in Table 25. (The "Chemical Exchange" zone referred to in the Table is discussed further in the following paragraph).

Based on the core analyses and well log data, a fence diagram including the pilot area was prepared; the pilot area portion of which is shown on Fig. 38. A comparison and analysis of core and log data leads to a proposed three-layer model, Fig. 39. For purposes of comparing the performance of the two micellar-polymer designs via numerical simulation, the pilot area values of h , ϕ and K_a were successively averaged into the values shown in Fig. 40. The "Chemical Exchange" zone is taken as the region of low porosity and permeability lying above and below the net pay zone. The "Chemical Exchange" zone is looked upon as a region which might interact in an adverse way during the micellar-polymer flood with the chemicals which lower interfacial tension and act as mobility control agents. However, this zone is considered to be non-pay for primary or secondary recovery calculations, since log analysis and core studies indicate that no substantial fluid movement takes place in it.

B. Pressure Pulse Tests

The purpose of the pressure pulse test was three-fold: i) to show qualitative continuity across the pattern, ii) to obtain absolute values of permeability to use in numerical simulation programs, and iii) to obtain an indication of directional permeability trends, i.e. reservoir anisotropy. Tests 1 and 2 were shake-down runs. Test 3 was a single pulse test, i.e., with an essentially unlimited fall-off interval. Since a solution to this Test 3 set of initial and boundary conditions did not exist in the reference literature, a new analysis was developed, Appendix I. Figure 10 shows the theoretically predicted matching data points in place on the observed data curves. The agreement is excellent. Table 26 presents the results of the corresponding analysis.

The transmissibility ($T = kh/\mu$) and storage ($S = \phi ch$) values obtained from the conventional analysis of data on Wells #1-15, #6-13, and #12-7 are in close agreement. This is a good indication of reservoir continuity. By using log, core and fluid property data to obtain representative values for effective viscosity and net sand thickness, an effective permeability between source and responding wells was calculated. The effective permeabilities

are to water at low oil saturation. These permeabilities compare favorably with analogous values which can be calculated using the results of both routine core analysis from the pilot area wells and k_{rw} data previously obtained in Unit 'A'. A k_{rw} of 10-20% at flood-out is expected, as indicated by the upper terminus of the k_{rw} experimental curve in Fig. 23. From this, and an average absolute permeability of about 1050 md, as calculated from core analysis, an effective permeability in the range of 100-200 md may be determined, agreeing with the values in Table 26.

The data for the #12-1/7-5 well pair appear to be the result of two-phase flow, gas saturation, or a reservoir anomaly; or perhaps some combination of all these factors between these two wells. The core and log data from Well #MPP-3 indicate that any geological anomaly is to the southeast of #MPP-3. Additional pressure and tracer testing of the pilot wells will be required to fully discern the reason for the anomalous response and more completely describe reservoir properties in this area.

The anisotropic analysis of data from this test requires a value for the product $\mu\phi c$ for the pilot area. This was determined by averaging the results from the conventional analysis for Wells #1-15, and #12-7; this value, along with the other data from these wells, was then used to complete the anisotropic calculations.

The results of the anisotropic analysis are also summarized in Table 26. They are comparable to the results from the conventional analysis in that the degree of anisotropy ($K_{\max}^*/K_{\min}^*$) is relatively small, and that the magnitudes of $K_{\max}^*$ and $K_{\min}^*$ are within the range expected from core analysis. In addition, the indicated direction of maximum permeability is in general agreement with the direction from which water flood response in the pilot area is believed to have occurred. A thorough study of water flood performance histories of the wells in this vicinity indicates that the injected water moved from north to south through the pilot area.

C. Residual Oil Saturation and Tertiary Target Oil

A working estimate of the target oil available for tertiary recovery is a necessity in order to evaluate the performance of a tertiary pilot project. Final determination of the residual oil saturation and the target oil is currently in progress. However, a substantial amount of work has been completed. The results of special core tests and open hole logs indicate an ultimate residual oil saturation to water flooding of about 25-30%. In addition, the preliminary results of log-inject-log tests run on two wells, #MPP-1 and #MPP-3, also indicate ultimate residual oil saturations in this range. Table 27 is a summary of ultimate water flood S_{or} determined

from analyses of cores, both within the pilot area and at other locations within the Bell Creek Field. Table 28 summarizes the residual oil saturations that resulted from analysis of the open hole logs taken on the five wells drilled in the pilot area. These values were determined using a shallow investigating micro-resistivity device (Schlumberger's Micro-Spherically Focused Log). Table 29 summarizes the log-inject-log tests run on the two pilot injectors, #MPP-1 and #MPP-3.

The target oil available for tertiary recovery is a function of the inter-well residual oil saturation to water flood. The lower limit for target oil should be the value for the ultimate residual oil saturation to core flooding, i.e. 100% pore-to-pore and sweep efficiency. However, inter-well tertiary target oil is a function of these two efficiencies, and these effects must be considered in the determination of the average inter-well post-water flood oil saturation. The final value for this tertiary target oil saturation will be obtained using the Chemical Flood Simulator, following further refinement of the reservoir description in the pilot area. To this end, pressure transient and inter-well tracer testing will take place before the commencement of the chemical flood phase of the pilot project.

D. Pilot Area Reservoir Parameters

An analysis of the currently available data from cores, logs and pressure transient testing indicates that the reservoir in the pilot area consists of a single zone of net pay. Within the 40-acre five-spot, this zone averages 8.1 feet thick, 1,050 md air permeability, and 29% porosity, Fig. 40. It has an estimated current oil saturation of about 35%. In addition, the remaining sand above and below the net pay has been consolidated into an interval referred to as a "Chemical Exchange" zone. Although no substantial fluid movement appears to occur in this interval, its average properties in the 40-acre five-spot from core and log analyses are 5.4 feet thick, 65 md air permeability, and 20% porosity, Fig. 40. The current average static reservoir pressure in the pilot area is approximately 1,300 psig.

CHAPTER XI

WORK FORECAST, DECISION POINTS AND TIME LINE

Reservoir definition work will continue using tracer, mini-injectivity and pressure pulse techniques, in addition to and iterating with the on-going numerical simulation work. This effort leads to Decision Point 3, "Site Configuration and Pattern Confirmation", Table 30. The purpose of Decision Point 3 is to indicate that the reservoir site description (ϕ , h , k and S_{or} as functions of reservoir location) is sufficiently accurate to lend confidence in the design and interpretation of the pilot performance.

Decision Point 4, "Pilot Test Project Confirmation", is based upon engineering and numerical simulation work, which in turn has as input the work in Decision Points 2 and 3. Decision Point 4 is where all previous work comes to a focus for the "Go/No-Go" decision with respect to the recommendation for injection of the chemical flood system. Decision Point 4 requires that there be reasonable confidence in four factors: 1) in the description of the site characteristics, 2) in the understanding of the operative micellar-polymer mechanisms as indicated by the ability to simulate the core flood tests, 3) in the related simulation of the

pilot behavior and performance, and 4) in the expected level of the pilot recovery.

Construction of the injection plant and fluid supply logistics depended upon the details of the micellar-polymer process which was selected, Chapter IX, Decision Point 2, which occurred in August 1977. Plant design and construction is now being carried forward with deliberate speed. This leads to Decision Point 5, "Fluid Injection Plant, Logistics and Field Monitoring in Operating State", Table 30.

The preflush, the soluble oil slug and polymer mobility control buffer will be injected during the first half of 1978, Fig. 41. Injection of the tapered polymer slug continues for 18 months, until November 1979. Tertiary pilot peak oil production should occur in the first half of 1979.

A field laboratory will be established as part of the injection plant and there will be an on-going program of monitoring of produced fluid composition and properties, and of quality control for supplied chemicals.

The project is currently on schedule, Fig. 41.

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TABLE 1
AVERAGE FORMATION AND ROCK PROPERTIES
MUDDY SAND UNIT 'A'
BELL CREEK FIELD, MONTANA

Type of Pay	Sandstone
Net Pay Thickness (ft.)	11.9
Irreducible Water Saturation (%)	23.6
Waterflood Residual Oil Saturation (%)	34.3
Air Permeability (md)	1000
Reservoir Temperature (°F)	110
Porosity (%)	26
Depth (ft.)	4525-4600
Initial Reservoir Pressure (psig)	1190
Reservoir Pressure (start of waterflood) (psig)	110
Initial Formation Volume Factor (RB/STB)	1.12
Formation Volume Factor (start of waterflood) (RB/STB)	1.05

TABLE 2

OIL VISCOSITY AND DENSITY DATA AT 110°F

Bottom Hole Sample

Well #12-11, Unit 'A'

Bell Creek Field, Montana

(March 1977, Atlantic Richfield)

<u>Pressure</u> <u>psig</u>	<u>Viscosity</u> <u>Centipoises</u>	<u>Density</u> <u>g/cc</u>
3000	7.47	0.8500
2500	7.05	0.8481
2000	6.60	0.8460
1500	6.22	0.8439
1000	5.86	0.8415
500	5.54	0.8391
220	5.39	0.8377
170 Bubble Point	5.35	0.8374
100	5.52	0.8388
0	6.22	0.8444

TABLE 3

HYDROCARBON ANALYSIS OF RESERVOIR OIL
Well #6-14, Unit 'A'

Core Laboratories, Inc.
January 1977

<u>COMPONENT</u>	<u>MOL PERCENT</u>	<u>WEIGHT PERCENT</u>	<u>DENSITY @ 60° F GRAMS PER CUBIC CENTIMETER</u>	<u>°API @ 60°F</u>	<u>MOLECULAR WEIGHT</u>
Hydrogen Sulfide	Nil	Nil			
Carbon Dioxide	0.01	Trace			
Nitrogen	0.02	Trace			
Methane	5.73	0.41			
Ethane	0.17	0.02			
Propane	0.39	0.08			
iso-Butane	0.81	0.21			
n-Butane	0.87	0.22			
iso-Pentane	1.75	0.56			
n-Pentane	1.26	0.40			
Hexanes	5.03	1.92			
Heptanes	8.80	3.69	0.7394	59.7	93
Octanes	7.57	3.66	0.7599	54.5	107
Nonanes	6.49	3.54	0.7788	50.0	121
Decanes	6.06	3.69	0.7970	45.9	135
Undecanes plus	55.04	81.60	0.8951	26.4	329
	<u>100.00</u>	<u>100.00</u>			
Heptanes plus properties (POD)			0.8699	31.0	258
Heptanes plus properties (calculated)			0.8732	30.4	254

Charged at 2000 psig and 71°F

TABLE 4

HIGH TEMPERATURE DISTILLATION OF
HEPTANES PLUS FRACTION OF RESERVOIR OIL
Well #6-14, Unit 'A'

Core Laboratories, Inc.
January 1977

<u>Cumulative Volume Percent</u>	<u>Temperature °F</u>
IBP	160
1.2	175
2.5	188
3.7	200
4.5 (Heptanes)	212
5.4	223
6.2	235
7.8	245
8.9 (Octanes)	257
9.7	273
10.6	283
11.4	291
13.0 (Nonanes)	302
14.0	313
15.5	324
16.3	336
17.2 (Decanes)	347
Undecanes plus residue	82.8%

TABLE 5

ATMOSPHERIC OIL VISCOSITIES
CENTRIFUGED WELLHEAD SAMPLES
BELL CREEK FIELD, UNIT 'A'
(March 1977, Atlantic Richfield)

<u>Well Number</u>	<u>Viscosity - Centipoises</u>			<u>°API @ 60°F</u>	<u>Density, g/cc</u>		
	<u>85°F</u>	<u>110°F</u>	<u>150°F</u>		<u>85°F</u>	<u>110°F</u>	<u>150°F</u>
6-11	11.77	6.70	4.06	31.8	0.8564	0.8471	0.8323
7-5	11.39	7.01	4.10	31.5	0.8579	0.8486	0.8338
12-8	9.50	6.34	3.74	32.2	0.8542	0.8448	0.8300
12-11	9.69	6.26	3.73	32.2	0.8541	0.8448	0.8299
12-14	9.21	5.95	3.55	32.5	0.8526	0.8433	0.8285
12-6	9.62	6.43	3.84	32.2	0.8542	0.8448	0.8300
12-10	9.88	6.40	3.81	32.0	0.8554	0.8460	0.8312

Table 6

PHYSICAL PROPERTIES - BOTTOM HOLE SAMPLE*
 UNIT 'A' WELL #12-11
 Bell Creek Field, Montana
 (September 1976, Atlantic Richfield)

Pressure psig	FVF RVB/STB	<u>Flash PVT Data</u>	
		Total Gas in Solution SCF/STB	Gravity STO °API @ 60°F
3000	1.024	31.5	32.3
2500	1.026	31.5	32.3
2000	1.029	31.5	32.3
1500	1.032	31.5	32.3
1000	1.035	31.5	32.3
600	1.037	31.5	32.3
400	1.038	31.5	32.3
170	1.039	31.5	32.3

Separation Conditions for Flash Data: 0 psig and 74°F

Pressure psig	FVF RVB/RDB	<u>Differential PVT Data</u>		
		Gas in Solution SCF/RDB	Gas Conversion Factor SCF/RVB	Gas Gravity of Liberated Gas (air - 1.000)
3000	1.021	32		
2500	1.023	32		
2000	1.026	32		
1500	1.028	32		
1000	1.031	32		
500	1.034	32		
170	1.036	32		
85	1.032	19	31	0.665
0	1.022	0		1.100

Gravity of residual oil at 60°F from differential liberation - 32.3°API

*Two samples were combined and the study run on the composite. Bubble Point at 110°F and 170 psig.

SCF = cubic feet of gas at 60°F and 14.7 psia.

STB = barrel of stock tank oil at 60°F and 14.7 psia.

RDB = barrel of residual oil at 60°F and 14.7 psia from differential liberation

RVB = barrel of fluid (gas or saturated oil) at reservoir temperature and pressure

TABLE 7

RESERVOIR FLUID COMPOSITIONS
 BOTTOM HOLE SAMPLES - BELL CREEK FIELD, UNIT 'A'
 (March 1977, Atlantic Richfield)

<u>Component</u>	<u>Well 6 - 14</u> <u>Mol %</u>	<u>Well 12-3</u> <u>Mol %</u>	<u>Well 12-11</u> <u>Mol %</u>
Hydrogen Sulfide	Nil	Nil	Nil
Nitrogen	0.02	Nil	Nil
Carbon Dioxide	0.01	0.01	0.01
Methane	5.73	4.12	5.54
Ethane	0.17	0.15	0.12
Propane	0.39	0.35	0.64
Iso-Butane	0.81	0.82	0.81
N-Butane	0.87	0.73	1.64
Iso-Pentane	1.75	1.63	2.26
N-Pentane	1.26	0.99	1.99
Hexanes	5.03	4.02	5.32
Heptanes Plus	83.96	87.18	81.67
TOTAL	100.00	100.00	100.00

Properties of Heptanes Plus:

°API @ 60°F =	31.0	30.4	31.1
Density @ 60°F g/cc =	0.8699	9.8730	0.8696
Molecular Weight:	258	257	258

TABLE 8

BRINE COMPOSITIONS
BELL CREEK FIELD, UNIT 'A'
(July 1977, Atlantic Richfield)

	APPROXIMATE ORIGINAL BRINE (15-7) (mg/l)	MADISON WATER SUPPLY WELL (mg/l)	CURRENT PRODUCED BRINE				
			MPP-1 (mg/l)	MPP-3 (mg/l)	14-14 (mg/l)	23-6 (mg/l)	26-4 (mg/l)
Sodium	2572	75	393	2040	1250	1387	2350
Calcium	22	182	14	15	11	12	22
Magnesium	13	52	13	7	4	5	12
Chloride	2690	107	248	2680	1200	1400	2520
Sulfate	5	497	19	24	13	0	0
Carbonate	0	0	0	0	0	0	0
Bicarbonate	1830	201	700	847	1280	1310	2020
Total Solids	7402	1114	1387	5613	3758	4174	6924
pH	8.2	7.3	8.0	8.2	8.1	7.6	8.0

TABLE 9

PRODUCTION HISTORY
BELL CREEK FIELD
UNIT 'A'

ORIGINAL OIL IN PLACE	=	122,000,000
PRIMARY PRODUCTION	=	21,957,000
CUMULATIVE PRODUCTION (7-1-77)	=	45,814,000
SECONDARY RESERVES	=	12,000,000
ULTIMATE PRIMARY + SECONDARY	=	58,000,000
OIL REMAINING AFTER WATER FLOOD	=	64,000,000

TABLE 10

BELL CREEK FIELD CONFORMANCE TO PREFERRED
CHARACTERISTICS FOR MICELLAR-POLYMER FLOODING

<u>Reservoir Property</u>	<u>Column 1 Preferred Characteristics</u>	<u>Column 2 Bell Creek Unit 'A' Pilot Site</u>
1. Formation	Sandstone	Sandstone
2. Temperature	<175°F	110°F
3. Areal Sweep of Water Flood	>50%	70% - 95%
4. Producing Zone Sand	>10 ft.	8.1 ft.*
5. Permeability to Brine	>10 md.	$k_{rw} = .1 - .2$ at S_{or} $k_{air} = 1050$ md. avg.
6. Viscosity at Res. Temperature	<20 cp.	<7 cp.
7. S_{or} (Post Water Flood)	>30%	~35%
8. Reservoir Continuity	Good	Excellent
9. Wettability	Oil or Water Wet	Water Wet
10. Well Spacing	>10 Acre	Same as Existing Full Field - 40-acre
11. Formation Water Salinity (Chlorides)	<20,000 ppm	1300 (Produced)
12. Divalent Ions Ca^{++} , Mg^{++}	<500 ppm	225 (Supply)
13. TDS Water	<50,000 ppm (Formation) < 5,000 ppm (Injection)	3500 ppm (Produced) 1115 ppm (Supply)
14. Oil Gravity	20-35 API	34.3 API

* Pilot Area: (Full field Unit 'A' average net pay is 11.9 feet.)

TABLE 11

MICELLAR-POLYMER PROCESSES

BELL CREEK OPTIMAL DESIGNS

<u>SLUG</u>	<u>OIL-EXTERNAL HIGH CONCENTRATION</u>		<u>WATER-EXTERNAL LOW CONCENTRATION</u>	
Preflush	High pH Silicate	10% PV	NaCl (or Other Inorganic Salt)	40% PV
Micellar	7.6% Active Sulfonate - Solvent (volume %)	3% PV *	2.8% Active Sulfonate - Alcohol (weight %)	12% PV
Polymer	Graded Concentration Polyacrylamide (950 ppm)	60% PV	Graded Concentration Polyacrylamide (1250 ppm)	60% PV

*Contains approximately 50% water.

TABLE 12

RECOVERY OF BELL CREEK CRUDE OIL
BY WATER-EXTERNAL MICELLAR SOLUTIONS

Run	Micellar Fluid Formulation	Polymer Formulatioi.	Oil Recovery, Percent S _{or} @ 1.0 P.V.
3T-12	Stepan Petrostep 465 + NAA (25) in 0.6% NaCl - 7.6 cp	1500 ppm Xanflood in 0.6% NaCl - 23 cp	79 (82 @ 1.4 P.V.)
2T-15	Stepan Petrostep 465 + NAA (25) in 0.3% NaCl - 6.0 cp	1500 ppm Xanflood in 0.3% NaCl - 23 cp	71 (75 @ 1.4 P.V.)
1T-20	Stepan Petrostep 465 + NAA (25) in 0.3% NaCl - 8.2 cp	2500 ppm Xanflood in 0.3% NaCl - 105 cp	84 (87 @ 1.3 P.V.)*
3T-16	Stepan Petrostep 465 + NAA (25) + 1500 ppm Xanflood in 0.3% NaCl - 36 cp	2500 ppm Xanflood in 0.3% NaCl - 105 cp	66 (67 @ 1.3 P.V.)*
1T-17	Stepan Petrostep 465 + NAA (25) + 1500 ppm Xanflood in 0.47% NaCl - 42 cp	1500 ppm Xanflood in 0.47% NaCl - 29 cp	62 (63 @ 1.3 P.V.)
2T-16	Stepan Petrostep 465 + NAA (25) in 0.94% NaCl - 6.9 cp	1500 ppm Xanflood in 0.94% NaCl - 21 cp	53 (55 @ 1.3 P.V.)
4T-11	Stepan Petrostep 465 + NAA (25) in 0.94% NaCl - 6.8 cp	1500 ppm Nalflo F in 0.94% NaCl - 12.3 cp	65 (67 @ 1.3 P.V.)
4T-10	Arco 498 + NAA (20) in 0.6% NaCl -16 cp	1500 ppm Xanflood in 0.6% NaCl - 23 cp	69 (73 @ 1.4 P.V.)
**	Phillips 23468-24 + NBA (25) in 0.9% NaCl - 6.4 cp	1500 ppm Xanflood in 0.9% NaCl - 30 cp	66 (69 @ 1.3 P.V.)

*In these two experiments the cores were pretreated with 5N NaCl; in all others a sodium silicate pretreatment was used.

**These results are the averages for three replicate experiments.

- NOTES: 1. Acronyms for cosolvents in micellar fluids formulations: NAA = normal amyl alcohol, NBA - normal butyl alcohol.
2. Cosolvent concentration indicated in parentheses represents percent by weight of mixture of cosolvent and as-received surfactant.
3. All sulfonate concentrations four percent by weight of 100 percent active.
4. Viscosities evaluated at 110°F, 10 sec⁻¹.

TABLE 13

SELECTION ALGORITHM
PROCESS A AND PROCESS B

CASE	COMPONENT I	COMPONENT II	COMPONENT III	
	<u>LABORATORY CORES</u>	<u>SIMULATION LABORATORY CORES</u>	<u>SIMULATION PILOT/FIELD</u>	<u>DECISION</u>
I	$A \approx B$	A, B	$A > B$	A
II	$A > B$	A, B	$A < B$	B, if understand reversal A, if do not understand
III	$A > B$	*NS, NS	NS, NS	A
IV	$A > B$	A, NS	A, NS	A
V	$A > B$	NS, B	NS, B	Technical Judgment
VI	$A \approx B$	A, B	$A \approx B$	Technical Judgment
		*No Simulation		

TABLE 14

OVERALL COMPARISON
% RECOVERY

Berea 4' Cores, Bell Creek Fluids

<u>STANDARD TEST</u>	<u>OIL-EXTERNAL</u>	<u>WATER-EXTERNAL</u>
	<u>(%)</u>	<u>(%)</u>
1A OPTIMAL DESIGN	87	68
	86	74
2A FRACTION SLUG (3/4)	84	57
	(1/2)	43
2B Ca ⁺⁺ MAXIMUM	50 (no PF*)	44 (with PF*)
	86 (with PF*)	

*Preflush

1. Density of pure components.
2. Compressibility of reservoir fluid.
3. Retention of sulfonate on Bell Creek rock under design conditions.
4. Retention of sulfonate on Bell Creek rock equilibrated with a calcium containing brine.
5. Retention of polymer on preflushed Berea rock.
6. Retention of polymer on preflushed Bell Creek rock.
7. Cation exchange capacity for Bell Creek rock.
8. Cation exchange isotherm for Bell Creek rock.
9. Effect of sacrificial agent on cation exchange capacity.
10. Water-oil relative permeability in both drainage and imbibition directions for Bell Creek rock.
11. Activity coefficient curve as a function of capillary number.
12. Phase diagrams.
13. Interfacial tensions.
14. Viscosities.

TABLE 16

EXISTING WELLS, COMPLETION DATA

<u>Well No.</u>	<u>TD (ft)</u>	<u>PBTD (ft)</u>	<u>8-5/8" Surface Casing (ft)</u>	<u>5-1/2" Producing Casing (ft)</u>	<u>Perforation</u>
1-15	4750	4720	182	4747	4657 - 4660
1-16	4785	4783	173	4783	4702 - 4716
6-13	4642	4575	160	4610	4503 - 4515
7-4	4754	4719	139	4747	4585 - 4595
7-5	4638	4600	155	4643	4557 - 4561
12-1	4760	4722	152	4757	4624 - 4631
12-2	4780	4716	N/A	4762	4627 - 4638
12-7	4760	4691	185	4735	4587 - 4597
12-8	4710	4650	160	4687	4581 - 4587

TABLE 17

NEW WELL COMPLETION DATA

<u>Well No.</u>	<u>TD (ft)</u>	<u>PBTD (ft)</u>	<u>8-5/8" Surface Casing (ft)</u>	<u>5-1/2" Producing Casing (ft)</u>	<u>Slotted Liner (ft)</u>
MPP-1	4820	4793	181	4793	4635-4649
MPP-2	4880	4862	189	4862	4709-4718
MPP-3	4750	4703	182	4703	4602-4610
MPP-4	4850	4837	203	4835	4680-4691
MPP-5	4785	4750	180	4780	NONE

TABLE 18
CONVENTIONAL CORE ANALYSIS
MPP-1

SAMPLE NUMBER	DEPTH	PERMEABILITY TO AIR (MD)		POROSITY	FLUID SATURATIONS	
		HORIZONTAL	VERTICAL		OIL	WATER
	4640-4642	SHALE				
1	4642-4643	6.3	3.7	19.1	2.4	90.7
2	4643-4644	9.0	8.2	11.0	1.8	78.6
3	4644-4645	76	3.5	23.6	2.7	79.7
4	4645-4646	33	1.2	16.7	7.9	79.3
5	4646-4647	2629	2253	37.0	11.0	81.8
6	4647-4648	2582	2160	33.1	21.8	66.4
7	4648-4649	2019	1972	34.9	7.9	83.7
8	4649-4650	155	107	22.6	28.1	66.1
9	4650-4651	864	494	34.7	11.6	79.0
10	4651-4652	676	45	32.4	14.2	73.2
11	4652-4653	548	56	22.5	6.6	69.7
12	4653-4654	2159	1314	17.3	4.0	85.6
13	4654-4655	21	4.3	24.7	16.9	59.1

Note: Cut 22' recovered 15'

Samples not depth corrected

TABLE 19
CONVENTIONAL CORE ANALYSIS
MPP-2

SAMPLE NUMBER	DEPTH	PERMEABILITY TO AIR (MD)		POROSITY	FLUID SATURATIONS	
		HORIZONTAL	VERTICAL		OIL	WATER
	4700-4705	SHALE				
1	4705-4706	2.6	2.1	21.5	0.4	85.0
2	4706-4707	466	308	23.6	15.2	67.1
3	4707-4708	20	15	21.0	6.0	68.6
4	4708-4709	8.8	0.70	21.7	0.4	83.7
5	4709-4710	2329	2066	32.3	29.5	59.5
6	4710-4711	2854	2780	33.4	13.1	59.1
7	4711-4712	1239	531	32.5	13.1	59.9
8	4712-4713	1183	409	17.8	17.7	66.7
9	4713-4714	2704	2066	31.9	18.5	65.8
10	4714-4715	254	172	33.4	10.8	72.7
11	4715-4716	1.0	0.40	18.8	13.9	65.3

Note: Cut 22' recovered 16'

Samples not depth corrected

TABLE 20
CONVENTIONAL CORE ANALYSIS
MPP-3

<u>SAMPLE NUMBER</u>	<u>DEPTH</u>	<u>PERMEABILITY TO AIR (MD)</u>		<u>POROSITY</u>	<u>FLUID SATURATIONS</u>	
		<u>HORIZONTAL</u>	<u>VERTICAL</u>		<u>OIL</u>	<u>WATER</u>
1	4600-4601	23	12	27.2	17.8	59.9
2	4601-4602	5821	5352	29.0	22.5	72.2
3	4602-4603	130	107	25.0	19.9	61.2
4	4603-4604	2028	1897	32.5	18.8	61.2
5	4604-4605	249	21	30.3	14.9	64.9
6	4605-4606	2967	2535	23.9	17.4	66.9
7	4606-4607	0.63	0.06	13.8	4.7	85.8
8	4607-4608	4.7	0.36	15.4	4.2	87.9
	4608-4617	LOST RECOVERY				

Note: Cut 17' recovered 8'

Samples not depth corrected

TABLE 21
CONVENTIONAL CORE ANALYSIS
MPP-4

<u>SAMPLE NUMBER</u>	<u>DEPTH</u>	<u>PERMEABILITY TO AIR (MD)</u>		<u>POROSITY</u>	<u>FLUID SATURATIONS</u>	
		<u>HORIZONTAL</u>	<u>VERTICAL</u>		<u>OIL</u>	<u>WATER</u>
1	4680-4681	2084	2009	29.6	14.8	71.7
2	4681-4682	2141	16	30.8	19.8	69.3
3	4682-4683	6573	6197	30.9	20.7	70.7
4	4683-4684	260	260	19.8	18.8	59.1
5	4684-4685	147	0.40	14.8	3.2	75.8
	4685-4697	SHALE				
	4697-4703	LOST RECOVERY				

Note: Cut 24' recovered 17'

Samples not depth corrected

TABLE 22
CONVENTIONAL CORE ANALYSIS
MPP-5 *

<u>SAMPLE NUMBER</u>	<u>DEPTH</u>	<u>PERMEABILITY TO AIR (MD)</u>		<u>POROSITY</u>	<u>FLUID SATURATIONS</u>	
		<u>HORIZONTAL</u>	<u>VERTICAL</u>		<u>OIL</u>	<u>WATER</u>
	4657-4668	SHALE				
1	4668-4669	1.3	1.0	5.3	3.6	72.1
2	4669-4670	55	42	26.7	10.2	66.5
3	4670-4671	94	82	20.1	9.3	68.4
4	4671-4672	0.60	0.46	22.5	6.3	73.6
5	4672-4673	480	212	32.1	13.6	59.1
6	4673-4674	1220	986	31.4	14.9	60.6
7	4674-4675	2300	2113	30.5	19.9	56.4
8	4675-4676	201	0.01	33.2	11.8	59.4
9	4676-4677	816	480	30.3	11.6	66.1
10	4677-4678	1389	1032	33.2	11.3	68.6
11	4678-4679	4695	4694	35.4	19.3	64.7
12	4679-4680	178	5.4	32.6	17.3	60.5
13	4680-4681	497	393	30.7	10.4	72.3
14	4681-4682	59	0.60	24.3	9.5	69.3
15	4682-4683	22	0.63	22.0	17.1	60.9
	4683-4684	SHALE				

Note: Cut 29' recovered 27'

Samples not depth corrected

TABLE 23

AVERAGE PERMEABILITY AND POROSITY OF NET PAY
FROM CORE ANALYSES MPP WELLS

<u>WELL</u>	<u>AVERAGE K (MD)¹</u>	<u>AVERAGE CORE ϕ (%)²</u>
MPP-1	1050	29
MPP-2	1370	30
MPP-3	545	28
MPP-4	1660	28
MPP-5	613	31

¹ Geometric average of air permeabilities

² Thickness weighted average

TABLE 24
MICELLAR-POLYMER PILOT AREA LOGGING INFORMATION

<u>Drilling Fluid Base</u>	<u>Logs Run</u>	<u>Well Numbers</u>
Fresh Water	IES, SGR	6-13, 7-5, 12-1, 12-7, 12-8
Fresh Water	IES, SGR, FDC-GR	1-15, 1-16, 7-4, 12-2
Salt Water	DLL-MSFL, FED-CNL-GR, BHC-GR	MPP-1, MPP-2, MPP-4, MPP-5
Salt Water	DIL, DLL-MSFL, BHC-GR, FDC-CNL-GR	MPP-3

Abbreviations:

DIL	-	Dual Induction Log
DLL	-	Dual Laterolog
FDC	-	Compensated Formation Density Log
CNL	-	Compensated Neutron Log
BHC	-	Borehole Compensated Sonic Log
IES	-	Induction Electrical Survey
GR	-	Gamma Ray
MSFL	-	Micro-Spherically Focused Log

TABLE 25

AVERAGE RESERVOIR CHARACTERISTICS
IN 160 ACRE STUDY AREA
MICELLAR-POLYMER PILOT

WELL	NET PAY INTERVAL			CHEMICAL EXCHANGE INTERVAL		
	Thickness (ft)	ϕ (%)	K _{air} (md)	Thickness (ft)	ϕ (%)	K _{air} (md)
MPP-1	7	32	1000	7	22	50
MPP-2	9	31	1400	6	20	40
MPP-3	8	28	500	4	17	20
MPP-4	8	26	1700	5	21	150
MPP-5	10	31	600	6	20	65
#1-15	8	28	N/A	8	N/A	N/A
#1-16	10	27	N/A	8	20	N/A
#6-13	4	27	N/A	9	20	N/A
#7-4	4	26	N/A	7	16	N/A
#7-5	4	28	440	6	19	24
#12-1	7	29	N/A	5	13	N/A
#12-2	10	29	N/A	3	17	N/A
#12-7	3	25	N/A	7	17	N/A
#12-8	4	24	N/A	7	16	N/A
Average 40-Acre 5-Spot	8.1	29	1050	5.4	20	65
Average 160-Acre Area	7.1	27	1050	6.8	17	65
			ESTIMATED NET PAY	PORE VOLUME (BBL) CHEM. EX.		
40-Acre 5-Spot			729,200	335,100		
160 Acre Area			2,379,500	1,435,000		

TABLE 26

SUMMARY OF RESULTS FROM PULSE TEST ANALYSIS
PULSE TEST #3

CONVENTIONAL PULSE TEST ANALYSIS

Well Pair	$T = K^*h/\mu$ (md-ft/cp)	$S = \phi ch$ (ft/psi) $\times 10^{-6}$	Avg. h (ft)	Avg. K^* (md)	S/T (cp/md-psi) $\times 10^{-8}$	$\phi\mu c$ (cp/psi) $\times 10^{-6}$
#12-1:#1-15	525	7.44	7.0	75	1.417	1.063
#12-1:#6-13	684	9.78	5.0	137	1.430	1.959
#12-1:#7-5	1117	39.12	6.5	181	3.324	6.016
#12-1:#12-7	571	7.00	5.0	81	1.226	0.993

Avg. $\phi\mu c$ (#1-15:#12-7) = 1.028×10^{-6} ; $K^* = k_w$ at low oil saturation.

ANISOTROPIC INTERFERENCE ANALYSIS

$$\phi\mu c = 1.028 \times 10^{-6} \text{ cp/psi}$$

$$K_X^* = 133 \text{ md.}$$

$$K_{\max}^* \equiv K_X^* = 142 \text{ md.}$$

$$K_e^* = K_X^* K_Y^* = 112 \text{ md.}$$

$$K_Y^* = 98 \text{ md.}$$

$$K_{\min}^* \equiv K_Y^* = 89 \text{ md.}$$

$$K_X^*/K_Y^* = 1.6$$

$$\theta = 24.2^\circ$$

TABLE 27

SUMMARY OF ULTIMATE RESIDUAL OIL SATURATION
TO WATERFLOOD FROM CORE TESTS

<u>WELL</u>	<u>UNIT</u>	<u>DEPTH (ft)</u>	<u>S_{or} (%)</u>
MPP-1 (1)	A	4648-4649	23
MPP-2 (2)	A	4646-4647	28
#22-9	A	(3)	33.5
#23-1	A	4645-4646	22.8
#27-3	A	(4)	34.4
#4-2	C	(5)	30.4
#12-1	D	4702-4703	31.1
#12-8	D	4722-4723	40.2
#27-3	Ranch Creek	(6)	28.4

- (1) Composite of 2 core plugs
- (2) Composite of 4 core plugs
- (3) Average of 6 samples
- (4) Average of 3 samples
- (5) Average of 8 samples
- (6) Average of 5 samples

TABLE 28

RESIDUAL OIL SATURATION
FROM OPEN HOLE LOGS, MPP WELLS

<u>WELL</u>	<u>DEPTH</u> <u>(ft)</u>	$\phi_{\Delta t}$ (1) <u>(%)</u>	S_{xo} (2) <u>(%)</u>	ROS (3) <u>(%)</u>
MPP-1	4643-4650	31	67	33
MPP-2	4710-4718	31.5	65.5	34.5
MPP-3	4606-4610	29	82	18
MPP-4	4684-4690	30	73	27
MPP-5	4674-4683	31	81	19
AVERAGE				26.3

(1) Porosity determined using sonic Δt and core porosity correlation

(2) Saturation determined using readings from Micro-Spherically Focused Log and resistivity of mud-filtrate

(3) $ROS = 1 - S_{xo}$

TABLE 29

SUMMARY OF LOG-INJECT-LOG TESTS
ON MPP-1 AND MPP-3
(PRELIMINARY RESULTS)

<u>Well</u>	<u>Logging Tool</u>	<u>Avg. ϕ (%)</u>	<u>Σ_{wf} (c.u.)</u>	<u>Σ_{ws} (c.u.)</u>	<u>Avg. Σ_{ff} (c.u.)</u>	<u>Avg. Σ_{fs} (c.u.)</u>	<u>S_o (%)</u>
MPP-1	TDT-K, TDT-L	32	22.6	73.5	18.4	30.4	26
MPP-3	NLL	28	22	72	17	27	29

c.u. = capture units

Σ_{wf} = capture cross section of fresh water

Σ_{ws} = capture cross section of brine

Σ_{ff} = capture cross section of formation with fresh water

Σ_{fs} = capture cross section of formation with brine

$$S_o = 1 - \frac{\Sigma_{fs} - \Sigma_{ff}}{\phi(\Sigma_{ws} - \Sigma_{wf})}$$

TABLE 30
DECISION POINTS

<u>Decision Point</u>	<u>Title</u>	<u>Date</u>
1	Site Selection	12/76 (Passed)
2	Fluid System Selection	8/77 (Passed)
3	Site, Configuration & Pattern Confirmation	12/77
4	Pilot Test Project Confirmation	12/77
5	Fluid Plant, Logistics & Field Monitoring Operational	12/77

FIGURE 1
98

FIGURE 2
99

FIGURE 4
101

R 54 E

R 55 E

LEGEND:

EXAMPLE PRODUCING WELL
 • 7-5 WELL NUMBER

EXAMPLE INJECTION WELL
 / 1-15 WELL NUMBER

STATE OF MONTANA
 DEPARTMENT OF NATURAL RESOURCES AND CONSERVATION
 DIVISION OF LAND MANAGEMENT

TERTIARY PILOT STUDY AREA
BELL CREEK 'A' MUDDY SAND UNIT
CARTER & POWDER RIVER COUNTIES,
MONTANA

FIGURE 5
 102

FIGURE 6
103

BELL CREEK FIELD
UNIT "A"
TYPE LOG
MUDDY INFORMATION

FIGURE 7

GARY OPERATING COMPANY
9011 INVERNESS COURT EAST • ENGLEWOOD, COLORADO 80110 • 303/770-4710

FENCE DIAGRAM
MICELLAR POLYMER PILOT AREA
BELL CREEK 'A' MUDDY SAND UNIT
CARTER & POWDER RIVER COUNTIES,
MONTANA

UNIT A

B BLS/MONTH - THOUSANDS

FIGURE 9
106

FIGURE 10
107

Surfactant - Solvent²

1. Micellar water contains inorganic and organic salts.

2. Stepan sulfonates and ethylene glycol monobutyl ether.

FIGURE 11
108

FIGURE 12
109

Surfactant + Solvent²

1. Water contained 250 mg/l of calcium ions.

2. Stepan sulfonates and ethylene glycol monobutyl ether.

High Calcium Brine¹

Modified
Creek
de Oil

FIGURE 13
110

Surfactant + Solvent²

1. Water contained 950 ppm
of active polyacrylamide.

2. Stepan sulfonates and ethylene
glycol monobutyl ether.

Polymer
Solution¹

Modified
Bell Creek
Crude Oil

FIGURE 14
111

FIGURE 15
112

OPTIMAL SALINITY CURVES

FIGURE 16
113

EFFECT OF SALINITY ON FINAL OIL SATURATION

FIGURE 17
114

EFFECT OF POLYMER CONCENTRATION ON FINAL OIL SATURATION

10 % PV Slug of 2 wt % Stepan 465 + 1.28 wt %
Normal Amyl Alcohol
Cyanatrol WF 950S Polymer
Preflush, Micellar Slug and Polymer Drive contain
3500 ppm TDS

FIGURE 18
115

SELECTION METHODOLOGY COMPONENTS

I. LABORATORY CORE TESTS

FLUIDS: BELL CREEK

ROCK: BEREA, BELL CREEK

II. NUMERICAL SIMULATION CORE RESULTS

III. NUMERICAL SIMULATION PILOT / FIELD

BOTTOM LINE

OIL RECOVERY / \$ COST

BELL CREEK

FINAL DESIGN % RECOVERY

(BEREA - 4' CORE BELL CREEK FLUIDS)

FIGURE 20
117

1 DIMENSIONAL ECONOMICS

BELL CREEK

FINAL DESIGN % RECOVERY

BELL CREEK 2" CORE PLUGS

SEQUENCED UP TO 12"

BELL CREEK FLUIDS

FIGURE 22
119

FIGURE 23
120

FIGURE 24
121

UNION - 0.03 P.V. Slug

FIGURE 25
122

ARCO - 0.12 P.V. Slug

FIGURE 26
123

BELL CREEK

FINAL DESIGN % RECOVERY

(BEREA - 4' CORE BELL CREEK FLUIDS)

FIGURE 27
124

FIGURE 28
125

FIGURE 29
126

PRESENT VALUE CASH FLOW AFTER TAX PILOT/FIELD 5 SPOT

FIGURE 30
127

EXISTING WELL COMPLETION
WELL #1-15

FIGURE 31
128

NEW WELL COMPLETION
WELL #MPP-1

FIGURE 32
129

MPP-1

LC = LOST CORE

FIGURE 33
130

MPP-2

LC = LOST CORE

FIGURE 34
131

MPP-3

LC = LOST CORE

FIGURE 35
132

MPP-4

LC = LOST CORE

FIGURE 36
133

MPP-5

LC = LOST CORE

FIGURE 37
134

FIGURE 38
135

FIGURE 39
136

* Geometric Avg. of 23 & 5821 md.
 ϕ = Porosity from Density log vs. ϕ_{core} correlation
 L.C. = Lost Core
 ** Thickness weighted average for ϕ
 Geometric average for K_a for given well

PILOT AREA ZONATION

ZONE DIAGRAM

PAY
ZONE

* CHEMICAL
EXCHANGE
ZONE

FIGURE 40
137

$\bar{h}$

$\bar{\phi}$

$\bar{k}_a$

OIP }
PWF }

PROPERTY TABLE

PAY

CHEM. EX.

8.1'

5.4'

29 %

20 %

1050 md

65 md

35 %

TIME LINE - BELL CREEK PILOT

FIGURE 41
138

APPENDIX I

EQUATIONS FOR CONVENTIONAL ANALYSIS OF PULSE TESTS

Diffusivity Equation Describes Phenomena For Radial Flow:

$$(1) \quad \frac{1}{r} \frac{\partial}{\partial r} \left(r \frac{\partial P}{\partial r} \right) = \frac{\partial^2 P}{\partial r^2} + \frac{1}{r} \frac{\partial P}{\partial r} = \frac{\phi \mu c}{K} \frac{\partial P}{\partial t}$$

Assumptions: Small pressure gradients
 Constant rock properties
 Small and constant fluid compressibility
 (i.e. no gas)
 Radial flow
 Homogeneous and isotropic
 Uniform thickness
 Constant ϕ , K and μ
 Negligible gravity forces

"Line source" solution to this equation for well in
 "infinite" reservoir is (producing well)

$$P(r, t) = P_i - \frac{q \mu \beta}{2 \pi k h} \left[-1/2 E_i \left(-\frac{\phi \mu c r^2}{4 K t} \right) \right]$$

$$\text{Let: } T = \frac{K h}{\mu} \quad S = \phi c h$$

P = psig
 βq = res. bbl/day { (+) for prod. and (-) for inj. }
 T = md-ft/Cp
 t = hr
 r = ft
 S = ft/psi
 ϕ = fraction

For a single pulse:

$$(2) \quad P = P_i - \frac{70.6 \beta q}{T} \left[-E_i \left(\frac{-948.3 S r^2}{T(t)} \right) + E_i \left(\frac{-948.3 S r^2}{T(t - \Delta t)} \right) \right]$$

Δt = pulse length (hr.)

The theory of superposition holds
 Therefore consider a single pulse superimposed on a
 linear decline

$$(3) \quad P(r, t) = P_i + m t - \frac{70.6 \beta q}{T} \left[-E_i \left(\frac{-948.3 S r^2}{T(t)} \right) + E_i \left(\frac{-948.3 S r^2}{T(t - \Delta t)} \right) \right]$$

Figure 1 illustrates the relationships of the various parameters.

Figure 1

Differentiating Equation (3) with respect to time:

$$\left. \frac{dP}{dt} \right|_{t = \Delta t + t_l} = m = m \frac{-70.6\beta q}{T} \frac{\text{Exp}\left[\frac{-948.3 \text{ Sr}^2}{T(t)}\right]}{t} - \frac{\text{Exp}\left[\frac{-948.3 \text{ Sr}^2}{T(t-\Delta t)}\right]}{t-\Delta t}$$

$$\frac{\text{Exp}\left[\frac{-948.3 \text{ Sr}^2}{T(t)}\right]}{t} = \frac{\text{Exp}\left[\frac{-948.3 \text{ Sr}^2}{T(t-\Delta t)}\right]}{t-\Delta t}$$

$$\text{Let: } t_{dl} = \frac{t-\Delta t}{\Delta t} = \frac{t_l}{\Delta t} \quad t = t_{dl} \Delta t + \Delta t$$

$$t = \Delta t (1 + t_{dl})$$

$$\text{Then: } \frac{\text{Exp}\left[\frac{-948.3 \text{ Sr}^2}{T\Delta t(t_{dl}+1)}\right]}{\Delta t (1+t_{dl})} = \frac{\text{Exp}\left[\frac{-948.3 \text{ Sr}^2}{T\Delta t t_{dl}}\right]}{\Delta t t_{dl}}$$

$$\frac{-948.3 \text{ Sr}^2}{T\Delta t(t_{dl}+1)} - \ln(1+t_{dl}) = \frac{-948.3 \text{ Sr}^2}{T\Delta t t_{dl}} - \ln(t_{dl})$$

$$t_{dl} \ln \left[\frac{t_{dl}}{1+t_{dl}} \right] = \frac{948.3 \text{ Sr}^2}{T\Delta t} \left[\frac{1}{t_{dl}+1} - \frac{1}{t_{dl}} \right] t_{dl}$$

$$t_{dl} \ln \left[\frac{t_{dl}}{1+t_{dl}} \right] = \frac{-948.3 \text{ Sr}^2}{T\Delta t} \left[\frac{1}{t_{dl}+1} \right]$$

$$(4) \quad (t_{dl} + 1) t_{dl} \ln(1 + 1/t_{dl}) = \frac{948.3 \text{ Sr}^2}{T\Delta t}$$

$$\text{At } t = \Delta t + t_l = \Delta t + \Delta t t_{dl} = \Delta t (1 + t_{dl})$$

$$P = P_0 + m \Delta t (1 + t_{dl}) - \frac{70.6\beta q}{T} \left[-E_i \left(\frac{-948.3 \text{ Sr}^2}{T\Delta t (1+t_{dl})} \right) + E_i \left(\frac{-948.3 \text{ Sr}^2}{T\Delta t t_{dl}} \right) \right]$$

$$(5) \quad P - P_o = \Delta P = m \Delta t (1 + t_{d\ell}) - \frac{70.6 \beta q}{T} \left[-E_i \left(\frac{-948.3}{\Delta t (1 + t_{d\ell})} \frac{Sr^2}{T} \right) + E_i \left(\frac{-948.3}{\Delta t t_{d\ell}} \frac{Sr^2}{T} \right) \right]$$

$$T = - \frac{70.6 \beta q}{\Delta P - m \Delta t (1 + t_{d\ell})} \left[-E_i \left(\frac{-948.3}{\Delta t (1 + t_{d\ell})} \frac{Sr^2}{T} \right) + E_i \left(\frac{-948.3}{\Delta t t_{d\ell}} \frac{Sr^2}{T} \right) \right]$$

APPENDIX II

USE OF CHMFLD1

This program solves, by an explicitly formulated finite difference scheme, the convective transport equations for one and two phase flow, phase equilibrium being assumed within each grid block. True ternary phase behavior is assumed, the phase diagram having the form shown in Fig. 1. Two parameters input by the user specify the phase envelope, and an additional parameter specifies the tie lines. The simulator tracks two independent variables, VC and VO. VC is the total concentration, expressed as a volume fraction, of chemical in a grid cell, including chemical in all phases and chemical retained by adsorption. Likewise, VO is the total concentration of oil. The following is a list and description of input and output parameters, including suggestions for "base case" values of input parameters which have been used in the experimentation with the simulator.

Inputs:

1. Relative permeabilities, mobilities, cut-off saturations, and threshold chemical concentration - XN, XNW, XM, XMW, SCC, SWC, SORC, SORW, VCAM
2. Phase behavior, adsorption, slug composition and initial oil saturation -- XKC, XLAOC, XLOAC, VCR, UCIN, UOIN and VOIN.
3. Dispersion, slug size and output format - N, NX, NQ, DQ, QS and QT.

Description of Input Parameters:

A. Phase Behavior

Equilibrium phase behavior is assumed to be defined by the relations:

$$WCO = XKC \cdot WCA$$

$$WOA = XLOAC \cdot WCA$$

$$WAO = XLAOC \cdot WCO$$

where WCO and WCA are the chemical volume fractions in oleic and aqueous phases, respectively; WOA and WAO are the volume fractions of oil in the aqueous phase and brine in the oleic phase, respectively.

An example of a ternary diagram describing such phase behavior is shown in Fig. 1.

Suggested Base Case Values:

$$XKC = 0.0$$

$$XLOAC = 1.0$$

$$XLAOC = 1.0$$

B. Adsorption

The surfactant chemical adsorption is taken to be irreversible adsorption, at a level independent of concentration. Thus, the adsorption isotherm has the form:

In each grid cell of the simulator only total chemical concentration in excess of VCR is mobile or available for dissolution in a liquid phase.

Suggested Base Case Value: $VCR = 0.0$

C. Slug Composition

The slug composition is specified by (UCIN, UOIN) where UCIN is the volume fraction of chemical and UOIN is the volume fraction of oil in the slug.

Suggested Base Case Values:

$$UCIN = 0.25$$

$$UOIN = 0.0$$

D. Initial Oil Saturation

VOIN specifies the initial uniform oil saturation in the reservoir.

Suggested Base Case Value:

$$VOIN = 0.30$$

E. Relative Permeabilities, Mobilities, and Cut-Off Saturations

XP, XPW, XN, XNW, XM, XMW, SCC, SWC, SORC, SORW, VCAM are used in the simulator to approximate relative permeability relationships by the following functions:

Region A (see Fig. 1) - $WCA \geq VCAM$ relative permeabilities approximated by the forms:

$$k_{rw} = k_{orwc} \left[\frac{S_w - SCC}{1 - SCC - SORC} \right]^{XN} \quad SCC < S_w < 1 - SORC$$

$$k_{ro} = k_{oroc} \left[\frac{S_o - SORC}{1 - SCC - SORC} \right]^{XP} \quad SORC < S_o < 1 - SCC$$

$$XM = \frac{k_{orwc} \mu_{oc}}{k_{oroc} \mu_{wc}} = \text{water/oil mobility ratio}$$

Region B - $WCA \leq VCAM$

$$k_{rw} = k_{orw} \left[\frac{S_w - SWC}{1 - SWC - SORW} \right]^{XNW} \quad SWC \leq S_w \leq 1 - SORW$$

$$k_{ro} = k_{oro} \left[\frac{S_o - SORW}{1 - SWC - SORW} \right]^{XPW} \quad SORC \leq S_o \leq 1 - SWC$$

$$XMW = \frac{k_{orw} \mu_o}{k_{oro} \mu_w} = \text{water/oil mobility ratio}$$

Suggested Base Case Values:

$$XP = 1.5$$

$$XPW = 1.5$$

$$XN = 1.5$$

$$XNW = 1.5$$

$$XM = 1.0$$

$$XMW = 1.0$$

$$SCC = 0.3$$

$$SWC = 0.3$$

$$SORC = 0.3$$

$$SORW = 0.3$$

$$VCAM = 0.10$$

F. Dispersion

Physical dispersion must be approximated by choosing spatial and time discretizations so as to give a level of numerical dispersion approximately equal to the

level of physical dispersion desired. The number of spatial gridblocks is specified by "N", and the size of time discretization is given by DQ/N where DQ is an input parameter which should be chosen so that $1/DQ$ is larger than the expected highest dimensionless velocity in units of fractional distance per pore volume of a plane of constant composition.

Suggested Base Case Values:

$$N = 50$$

$$DQ = 0.2$$

G. Slug Size: QS is the slug size in pore volumes.

Suggested Base Case Value: $QS = 0.10$.

Output specifications:

QT specifies the total time in pore volumes which the user desires for the chemical flood to proceed. NQ specifies at which time increments data is to be output. Thus $NQ = 50$ specifies that at every 50th time increment data is to be output. Output then will be given in time increments of $DQ \cdot NQ/N$. NX specifies for which gridblocks data should be output. Thus, $NX = 2$ specifies that data is to be output for every second gridblock.

The time level in pore volumes of fluid injected at which a batch of data is output is indicated by a " $Q = \underline{\quad}$ ". A "VC" label is then output indicating that the proceeding table is the total concentration

(volume fraction) of chemical in each gridblock for which output is to be printed at indicated time level. Similarly "VO" labels the output volume fractions of oil.

The "ERC = ____" printed after the chemical volume fractions is the fraction of injected chemical which has been produced from the last gridblock up to and including that time step. Likewise, the "ERO = ____" printed after the oil volume fractions is the fraction of initial oil produced up to and including that time step.

Suggested Values:

NX = 1

NQ = 50

QT = 2.0

A free format may be used to input the data.

EXAMPLE TERNARY DIAGRAM CHMFLD I

FIGURE 1

USE OF CHMFLD2

This program solves, by an explicitly formulated finite difference scheme, the convective transport equations for one, two and three phase flow of four components -- oil, water, chemical and polymer -- phase equilibrium being assumed within each grid block. True ternary phase behavior is assumed, the phase diagram having the form shown in Fig. 2. The coordinates of the five points indicated on the diagram are input by the user. The simulator tracks three independent variables, VC, VO and CP. VC is the total concentration, expressed as a volume fraction, of chemical in a grid cell, including chemical in all phases and chemical retained by adsorption. Likewise VO is the total concentration of oil, and CP is the total concentration, in ppm, of polymer. The following is a list and description of input and output parameters, including suggestions for "base case" values of input parameters which have been used in the experimentation with the simulator.

Inputs:

1. Relative permeabilities and mobilities - XP, XPW, XN, XNW, XM, XCMWM, XCMWO and XMWO
2. Cut-off Saturations - SCC, SWC, SORC, SORW, and SRM
3. Phase behavior, adsorption, slug composition, initial oil saturation and polymer drive - VC1, VO1, VC2, VO2, VC3, VO3, VC4, VO4, VC5, VO5, VCR, UCIN, UOIN, VOIN, CPIN and FP.

4. Dispersion, slug size and output format - N, NX,
NQ, DQ, QS and QT

Description of Input Parameters:

- A. Phase Behavior: (VC1, VO1), (VC2,VO2), (VC3,VO3),
(VC4, VO4), and (VC5,VO5) are the coordinates of the
five points on the ternary diagram (Fig. 2) which
approximate the phase behavior of the physical system
to be modeled. The first coordinate of each pair is
a volume fraction of chemical, the second is a volume
fraction of oil. The tie lines in each of the three
two-phase regions are obtained by taking a constant
chemical partition coefficient in that region given
by:

Region B	XKC3 = VC2/VC1
Region C	XKC1 = VC3/VC1
Region D	XKC2 = VC3/VC2

Suggested Base Case Values:

VC1 = 0.05
VO1 = 0.05
VC2 = 0.05
VO2 = 0.90
VC3 = 0.20
VO3 = 0.50
VC4 = 0.30
VO4 = 0.30
VC5 = 0.30
VO5 = 0.40

- B. Adsorption: The surfactant chemical adsorption is taken to be irreversible adsorption, at a level independent of concentration. Thus the adsorption isotherm has the form:

In each grid cell of the simulator only total chemical concentration in excess of VCR is mobile or available for dissolution in a liquid phase.

Suggested base case value: $VCR = 0.0$

- C. Slug Composition: The slug composition is specified by (UCIN, UOIN) where UCIN is the volume fraction of chemical and UOIN is the volume fraction of oil in the slug.

Suggested Base Case Values:

$$UCIN = 0.10$$

$$UOIN = 0.0$$

- D. Initial Oil Saturation: VOIN specifies the initial uniform oil saturation in the reservoir.

Suggested Base Case Value: $VOIN = 0.30$

E. Polymer: A continuous bank of polymer of constant concentration CPIN, in ppm, follows directly behind the slug. The polymer is transported in the aqueous phase only, and then only when that aqueous phase is in equilibrium with other phases. It is assumed that the polymer's only effect is on the aqueous phase viscosity, and that the aqueous phase viscosity depends only on polymer concentration. The function, MUW(CPW), listed at the end of the program specifies the aqueous phase viscosity dependence on CPW, the aqueous phase polymer concentration, in ppm. The function, which may be changed by the user, is currently $MUW = 1.78 \times 10^{-4} CPW^{1.65}$, which approximates the functional relationship exhibited by Dow Pusher at 0.6 N. NaCl. The ratio of the polymer interstitial velocity to aqueous phase interstitial velocity, which may be different from unity because of adsorption and excluded pore volume, is specified by FP. Suggested base case values: FP = 1., CPIN=1500.

F. Relative Permeabilities, Mobilities and Cut-Off

Saturations: XP, XPW, XN, XNW, XM, XCMWM, XMWM, XCMWO, XMWO, SCC, SWC, SORC, SORW and SRM are used in the simulator to approximate relative permeability relationships by the following functions:

Region A (see Fig. 2) - three phases: water, oil, microemulsion, relative permeabilities approximated by the forms:

$$k_{rw} = k_{rwc}^0 \left[\frac{S_w - SCC}{1 - SCC - SORC} \right]^{XN} \quad SCC < S_w < 1 - SORC$$

$$k_{ro} = k_{roc}^0 \left[\frac{S_o - SORC}{1 - SCC - SORC} \right]^{XP} \quad SORC < S_o < 1 - SCC$$

$$k_{rm} = k_{rmc}^0 S_m \quad 0 < S_m < 1$$

$$XCMWM \equiv \frac{k_{rwc\mu mc}^0}{k_{rmc}^0} \quad (\text{in centipoises})$$

$$XCMWO \equiv \frac{k_{rwc\mu oc}^0}{k_{roc}^0} \quad (\text{in centipoises})$$

Region B - 2 phases, water, oil

$$k_{rw} = \frac{k_{rw}^0}{\mu_w} \left[\frac{S_w - SWC}{1 - SWC - SORW} \right]^{NW} \quad SWC \leq S_w \leq 1 - SORW$$

$$k_{ro} = \frac{k_{ro}^0}{\mu_o} \left[\frac{S_o - SORW}{1 - SWC - SORW} \right]^{PW} \quad SORC \leq S_o \leq 1 - SWC$$

$$XMWO \equiv \frac{k_{rw\mu o}^0}{k_{rw}^0} \quad (\text{in centipoises})$$

Region C - 2 phases: water, microemulsion

$$k_{rw} = k_{rwc}^0 \left[\frac{S_w - SCC}{1 - SCC - SRM} \right]^{XN} \quad SWC \leq S_w \leq 1 - SRM$$

$$k_{rm} = k_{rmc}^0 \left[\frac{S_m - SRM}{1 - SCC - SRM} \right]^{XM} \quad SRM \leq S_m \leq 1 - SWC$$

Region D - 2 phases: oil, microemulsion

$$k_{ro} = k_{ro}^o \left[\frac{S_m - SORC}{1 - SORC - SRM} \right]^{XP} \quad SORW \leq S_o \leq 1 - SRM$$

$$k_{rm} = k_{rm}^o \left[\frac{S_m - SRM}{1 - SORW - SRM} \right]^{XM} \quad SRM \leq S_m \leq 1 - SORW$$

Suggested base case values:

XP	=	1.5
XPW	=	1.5
XN	=	1.5
XNW	=	1.5
XM	=	1.5
XCMWM	=	1.0
XMWM	=	1.0
XCMWO	=	1.0
XMWO	=	1.0
SCC	=	0.3
SWC	=	0.3
SORC	=	0.0
SORW	=	0.3
SRM	=	0.3

- G. Dispersion: Physical dispersion must be approximated by choosing spatial and time discretizations so as to give a level of numerical dispersion approximately equal to the level of physical dispersion desired. The number of spatial gridblocks is specified by "N",

and the size of time discretization is given by DQ/N where DQ is an input parameter which should be chosen so that $1/DQ$ is larger than the expected highest dimensionless velocity in units of fractional distance per pore volume of a plane of constant composition.

Suggested base case values:

$$N = 50$$

$$DQ = 0.05.$$

H. Slug Size: QS is the slug size in pore volumes.

Suggested base case value: $QS = 0.10$.

Output Specification:

QT specifies the total time in pore volumes which the user desires for the chemical flood to proceed. NQ specifies at which time increments data is to be output. Thus, $NQ = 50$ specifies that at every 50th time increment data is to be output. Output then will be given in time increments of $DQ \cdot NQ/N$. NX specifies for which gridblocks data should be output. Thus $NX = 2$ specifies that data is to be output for every second gridblock.

The time level in pore volumes of fluid injected at which a batch of data is output is indicated by a " $Q = \underline{\quad}$ ". A "VC" label is then output indicating that the proceeding table is the total concentration

(volume fraction) of chemical in each gridblock for which output is to be printed at indicated time level. Similarly "VO" labels the output volume fractions of oil.

The "ERC = ____" printed after the chemical volume fractions is the fraction of injected chemical which has been produced from the last gridblock up to and including that time step. Likewise, the "ERO = ____" printed after the oil volume fractions is the fraction of initial oil produced up to and including that time step.

Suggested values:

NX = 1

NQ = 50

QT = 1.1

A free format may be used to input the data.

EXAMPLE TERNARY DIAGRAM CHMFLD 2

FIGURE 2