DOE/BC/14962-24
(OSTI ID: 750872)

THE UTILIZATION OF THE MICROFLORA INDIGENOUS TO AND PRESENT IN OIL-BEARING FORMATIONS TO SELECTIVELY PLUG THE MORE POROUS ZONES THEREBY INCREASING OIL RECOVERY DURING WATERFLOODING

Final Report
November 1999

By
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Lewis R. Brown
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Date Published: February 2000

Work Performed Under Contract No. DE-FC22-94BC14962

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Ridgeland, Mississippi

National Petroleum Technology Office
U.S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

DOE/BC/14962-24
Distribution Category UC-122

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EXECUTIVE SUMMARY

This is the final report on a Department of Energy "Class I Oil Program-Mid Term Activities" project entitled "The Utilization of the Microflora Indigenous to and Present in Oil-Bearing Formations to Selectively Plug the More Porous Zones Thereby Increasing Oil Recovery During Waterflooding". The 5.5 year project was divided into three phases. Those phases and their duration were – Phase I Planning and Analysis (9 months), Phase II Implementation (45 months), and Phase III Technology Transfer (12 months). The laboratory portions of the project were carried out at Mississippi State University and the North Blowhorn Creek Oil Field situated in Lamar Co., AL was the site of the field demonstration. Specifically, the objective of the project was to demonstrate the effectiveness of a microbial permeability profile modification technology (MPPM) to enhance oil recovery from a fluvial dominated deltaic reservoir and to document the scientific basis of the technology.

Simply stated MPPM involves adding nitrogen-containing and phosphorous-containing microbial nutrients to the injection water in a conventional waterflooding operation. The resulting microbial growth redirects water flow from the more porous zones to new unswept oil-bearing channels, thereby increasing the efficiency of the waterflooding. Feed and feeding regimes employed in the field demonstration were formulated on the basis of core flood experiments conducted using live cores from a newly drilled well in an area of the field not influenced by the waterflooding operation. The field demonstration design involved injecting nutrients into four injectors (test) and monitoring the surrounding production wells. For control, the producing wells surrounding four other injectors not receiving nutrients were monitored. Thus, the results from producing wells in the test patterns could be compared to results from similar wells in the same field as well as the historical data.

The success of the technology was shown by the recovery of 10,970 m^3 (69,000 bbl) of incremental oil during the first 42 months with a projected recovery of 64,000-95,000 m^3 400-600 MBO) and an extension of the economic life of the field by 60-137 months. The field wide distribution of the injected nutrients was clearly demonstrated by their presence in producing wells and in cores obtained from three wells drilled in the field after 22 months of nutrient injection. The role of microorganisms was shown by the presence of large numbers of microorganisms in cores from the three wells cited above. Proof that oil from unswept areas of the reservoir was present in the produced oil was shown by changes in the gas chromatographic profile and by a change in the composition of produced gases.

Attractive features of the MPPM are that it (1) may be employed in many geological formations amenable to waterflooding, (2) does not interfere with normal waterflooding activities, (3) is environmentally friendly, and (4) is the least expensive of all EOR processes in terms of cost per barrel of incremental oil recovered.

I. INTRODUCTION

A. Review of MEOR

The concept of using microorganisms to enhance oil recovery, MEOR, was first proposed in 1926 by Beckman [1]; but, it was not until the 1950's that the concept was actively researched by ZoBell and his colleagues[2-5]. Since that time, a number of diverse microbiological technologies has been developed to enhance oil recovery. For example, some microbial methods aid in paraffin removal while others are designed to modify heavy oil. Still other methods use microorganisms to produce chemicals, such as surfactants, polymers, or solvents that are useful in oil recovery processes, either in above ground facilities or *in situ.* Most of the methods are designed to treat single wells, and not the entire fields. This diversity of MEOR applications has led to a great deal of confusion in the petroleum industry and skepticism as to the merits of MEOR. Since most of the early research on MEOR in this country was conducted by industry, the results were proprietary and the only references thereto are to be found in the patent literature.

The target for enhanced oil recovery processes is the tremendous quantity of unrecoverable oil in known deposits. Roughly two-thirds [approximately 55.6×10^9 m^3 (350 billion bbl)] of all of the oil discovered in the U. S. is unrecoverable economically using current technology. Since one of the major attributes of MEOR technologies is its low cost, the question arises as to why MEOR has not been generally accepted by the petroleum industry. One of the reasons for this state of affairs is that many of the processes simply don't work. They were either based on untried ideas or on laboratory work alone and when subjected to field tests, they failed. Also, many people in the petroleum industry do not understand that MEOR is a multiplicity of technologies, not a single process. While there has been an increasing number of publications in the open literature on laboratory studies, their value in the field is only speculative.

Furthermore, reports on the deleterious activities of microorganisms in the oil field contribute to the skepticism of employing technologies using microorganisms. Even most reports on field trials are poorly documented and fail to meet normal standards for scientific acceptance. For example, the lack of adequate controls is glaring. This lack of controls is understandable in light of the fact that they are an added expense and will not contribute a single barrel of oil to the operator involved. Thus, subsidy to acquire the data to scientifically document the success of MEOR technology is needed if MEOR is to become an accepted tool for the oil industry.

It is also clear that scientific knowledge of the fundamentals of microbiology must be coupled with an understanding of the geological and engineering aspects of oil production in order to develop a meritorious MEOR technology. Furthermore, funds must be available to pay for the collection of the scientific documentation necessary to validate that particular MEOR technology.

The MEOR technology being demonstrated in the current project was developed in the 1980's at Mississippi State University with funds provided in part by industry[6] and improved under a Dept. of Energy (DOE) Grant[7] in the early 1990's. The Reservoir Class Program initiated by DOE in 1992 presented the opportunity to not only demonstrate the effectiveness of a specific MEOR technology but also to be able to design and execute an experimental program that would allow for the scientific validation of the results. In order to accomplish this goal, Hughes Eastern Corporation and Mississippi State University joined forces with DOE in a cooperative agreement . The team of principal investigators assembled for the project consisted of a microbiologist, a petroleum engineer, and an oil company executive, thus insuring that expertise necessary for the successful execution of the project was actively involved in the design, implementation, and evaluation of the demonstration.

Since the MEOR technology in this project differs in several ways from other MEOR technologies, it is important that these differences be clearly delineated. The present project is designed to enhance oil recovery from an entire oil reservoir rather than treat single wells. Even more important is the fact that this technology relies on the action of the *in situ* microflora, not microorganisms injected into the reservoir. The MEOR technology being demonstrated in this project is a microbial permeability profile modification technology (MPPM) wherein the addition of nutrients to the reservoir enables the microflora present to grow, thereby altering the sweep pattern of the injection water in a conventional waterflood operation. Thus, injection water is diverted from the larger channels to previously unswept areas of the reservoir resulting in an increased efficiency of the waterflood operation. It is important to note that employing this MPPM technology does not interfere with the normal waterflood operation. Also, it should be emphasized that the technology is environmentally friendly in that neither microorganisms nor hazardous chemicals are introduced into the environment. The microorganisms upon which the technology depends are already present in the reservoir and the microbial nutrients are commonly used plant fertilizers. This process is the cheapest of all EOR processes.

B. Objectives of the Project

The objectives of this project were (1) to demonstrate that the *in situ* microbial population in a fluvial dominated deltaic reservoir could be induced to proliferate to such an extent that they will selectively restrict flow in the more porous zones in the reservoir thereby forcing injection water to flow through previously unswept areas thus improving the sweep efficiency of the waterflood and (2) to obtain scientific validation that microorganisms are indeed responsible for the increased oil recovery.

One expected outcome of this new technology was the prolongation of economical life of the reservoir, i.e. economical oil recovery should continue for much longer periods in areas of the reservoir subjected to the MPPM technology than it would if it followed its historic trend.

This five and a half year project was divided into three phases of nine months, forty-five months, and twelve months. Phase I was devoted to planning and analysis and involved the drilling of two new wells to obtain cores for laboratory experimentation. During Phase II the field demonstration was carried out and Phase III was devoted to technology transfer.

II. DESCRIPTION OF THE OIL RESERVOIR

The North Blowhorn Creek Oil Unit (NBCU) is located in the Lamar County, AL about seventy-five miles west of Birmingham (See Figure 1). The field is in what is known geologically as the Black Warrior Basin. The producing formation is the Carter Sandstone of Mississippian Age at a depth of about 700 m (2300 feet). The field was discovered in 1979 and initially developed on 80-acre spacing. Waterflooding of the reservoir began in 1983. The initial oil in place in the reservoir was about 2.54 x 10^6 m^3 (16 million barrels), of which 874,430 m^3 (5.5 million barrels) had been recovered by the end of 1995. To date, North Blowhorn Creek is the largest oil field discovered in the Black Warrior Basin. Oil production peaked at almost 475 m^3/day (3000 BOPD) in 1985 and has since steadily declined. Currently there are 20 injection wells and 32 producing wells. Oil production at the outset of the field demonstration was about 46 m^3/day oil (290 BOPD), 1700 m^3/day gas (60 MCFD), and 493 m^3/day water (3100 BWPD) with a water injection rate at about 660 m^3/day (4150 BWPD). Projections at the beginning of the project were that about 1.59 x 10^6 m^3 of oil (10 MMBO) would be left unrecovered if some new method of enhanced recovery were not effective.

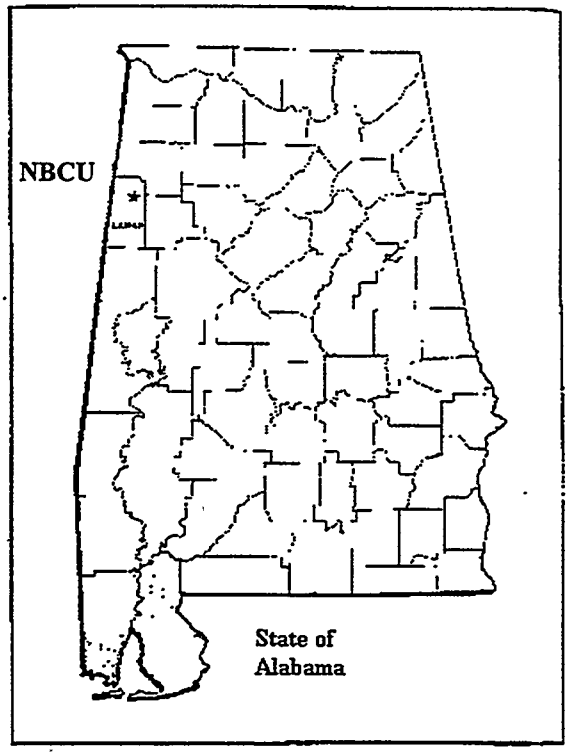


Figure 1. NBCU field location.

III. PRE-FIELD TRIAL STUDIES

A. Experimental Design

The concepts of the new technology evaluated in this project were scientifically sound and had been proven to be effective in laboratory experiments[6,7]. Nevertheless, it was deemed desirable to perform laboratory tests on live cores from the reservoir of interest. Two wells were drilled for this purpose and special core flood experiments were conducted in order to establish the exact concentration of, and schedule for additions of, nutrients to the injection water.

While the main purpose of drilling the two wells was to obtain cores suitable for use in the laboratory work, a secondary purpose was to obtain production data that would indicate the sweep efficiency of the existing waterflood.

At the conclusion of Phase I, two different feeding regimes were formulated for the field demonstration, each to be employed in two test injector wells.

B. Acquisition of Live Cores

Phase I of the project began with the drilling of two wells (see Figure 2) to obtain live cores and production data that would indicate how well the reservoir was being swept by the existing waterflooding. The two well locations were chosen in an area of the field where representative Carter sand thicknesses [approximately 6 m (20 ft)] could be expected and also in an area where bypassed oil could reasonably be expected to exist. The first well, NBCU 34-6 No. 3, was drilled in March 1994 and encountered 6.1 m (20 feet) of net Carter formation sand. However, probably due to the overbalanced drilling condition in the subnormally pressured reservoir, no increase in drilling rate occurred in the sand and the core point was missed.

The NBCU 34-6 No. 3 was completed and placed on rod pump. The well initially tested 4 m^3/day oil (25 BOPD), 0.16 m^3/day water (1 BWPD) and 142 m^3 (5 MCFD). By December 1994 the rate had decreased to 1.6 m^3/day oil (10 BOPD), 0 m^3/day water (0 BWPD) and 113 m^3/day gas (4 MCFD). Cumulative production was 533 m^3 oil (3354 BO), 38 m^3 water (241 BW), and 32.4 x 10^3 m^3 gas (1144 MSCF). The fact that the well exhibited low water cut compared to offset wells that typically produce 65-98% water was further evidence of the existence of bypassed oil. In December 1996, as a result of continued low fluid and low water cut production, the well was hydraulically refractured. The refracturing was very successful, resulting in an initial rate of 7.3 m^3/day oil (46 BOPD) with 0.08 m^3/day water (0.5 BWPD). The rate continued to improve and peaked at 13.7 m^3/day oil (103 BOPD) with 0.8 m^3/day water (5 BWPD) in May 1998. At this point the well accounted for almost one third of total unit production. After May the oil production began to decline as water production increased.

The second new well, NBCU 34-3 No. 2, was successfully drilled and cored during April, 1994. Because of the inability to pick a coring point by drilling rate increase in the first

well, the core point was picked in the second well strictly based upon where in the geologic section the sand should occur, without the necessity of actually having an increase in drilling rate

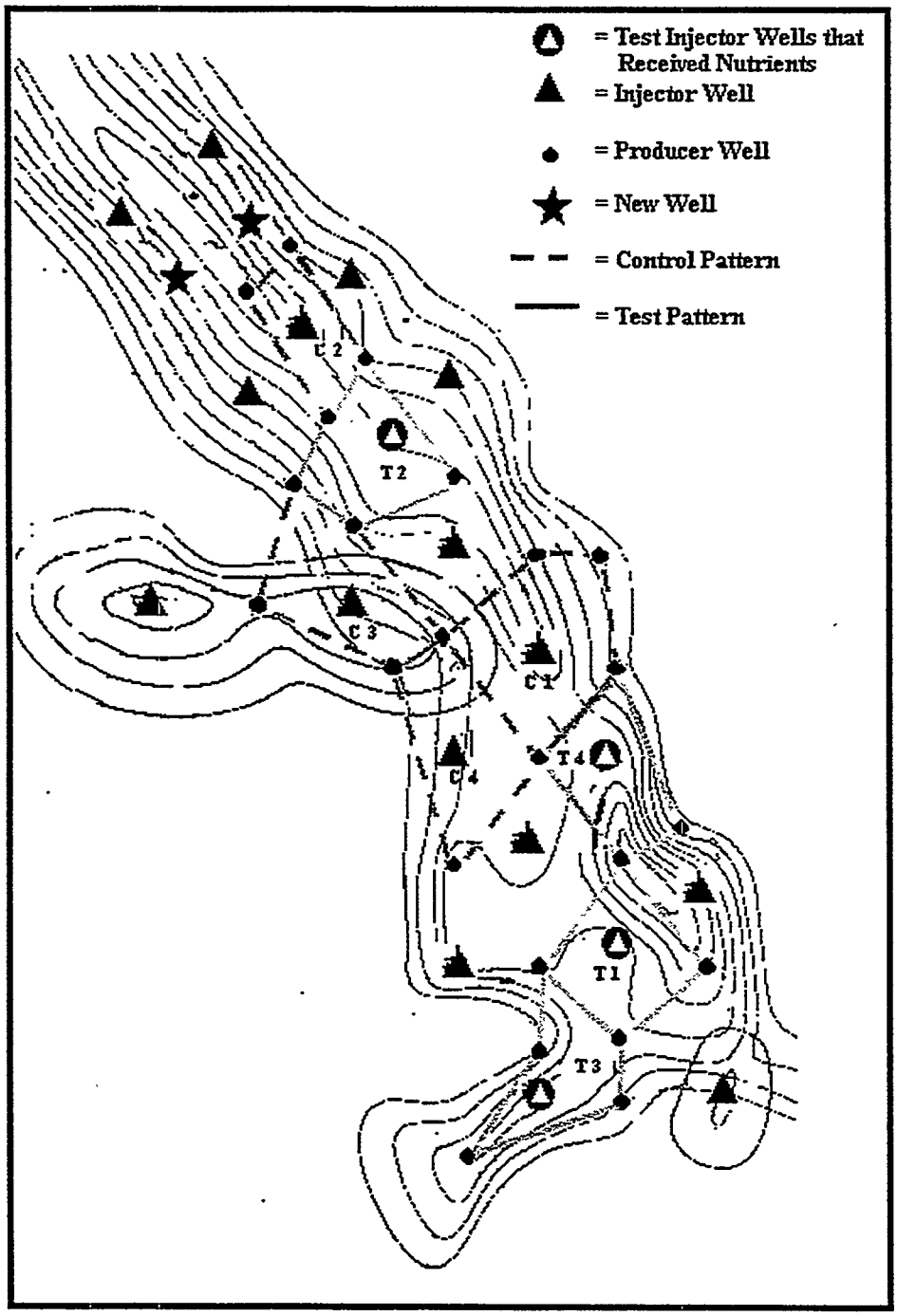


Figure 2. Approximate location of two new wells in NBCU.

to indicate penetration of the sand. The well encountered about 6.4 m (21 feet) of net Carter oil sand. About 6 m (20 feet) of the core was immediately collected using the special procedures outlined elsewhere in this report and transported to Mississippi State University for laboratory work. From visual observation of live oil running from the core (see Figure 3) as it was removed from the core barrel it was obvious that much oil remained in the reservoir. The well was completed and placed on rod pump for production.

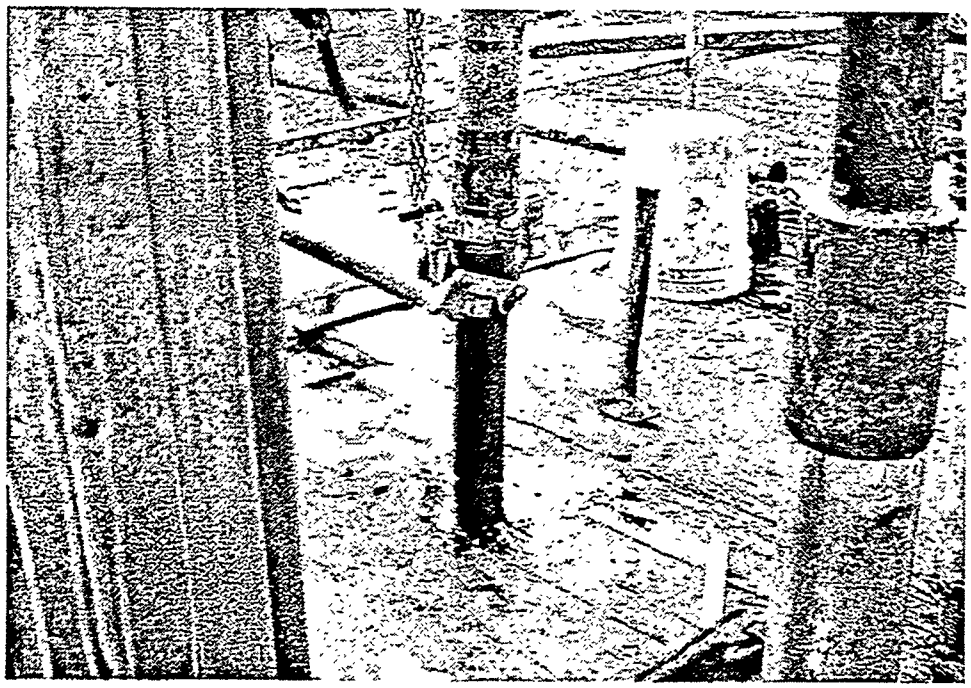


Figure 3. Core from well 34-3 No. 2. (Note oil seeping from core).

Representative production data could not be obtained initially due to the well pumping fluid containing large amounts of fracturing sand and relatively little fluid. The well tubing and pump had to be pulled several times to clean out sand. In June, the decision was made to re-fracture the well to remedy the sand production problem and obtain representative, commercial production from the well. The refracturing was successful in achieving both objectives, and soon afterward the well tested 6.8 m^3/day oil (43 BOPD), 6.8 m^3/day water (43 BWPD) and about 2265 m^3/day gas (80 MSCFD) on pump. By the end of December 1994, the producing rate had declined to 1.3 m^3/day oil (8 BOPD), 1.7 m^3/day water (11 BWPD), and 113 m^3/day gas (4 MSCFD). Cumulative production was 497 m^3 oil (3128 BO), 741 m^3 water (4659 BW), and 30,387 m^3 gas (1073 MSCF).

The cores were received as they were pulled from the core barrel (live cores). The cores were broken into 1-ft sections, wiped with 70% ethanol, and immediately placed in an anaerobic jar containing Gas Pak® disposable hydrogen and carbon dioxide generator envelopes to

produce anaerobic conditions in the jar (Becton Dickinson Gas Pak®). This procedure was completed within minutes, thus exposure to air was minimal which was of particular significance for microbiological studies. It should be pointed out that the pressure in the core tends to force fluid and/or gases outward, thereby reducing further the possibility of exposing the internal section of the core to air. The anaerobic containers were packed in ice, transported to the laboratory, and placed in a refrigerator at 4°C until needed.

C. Analytical Methods

1. Crushing of the Cores

When the cores were to be analyzed, they were removed from their containers under an atmosphere of nitrogen, again wiped with 70% ethanol, and cut into four-inch sections (top, middle, and bottom) using a sterile core saw (Rayteck Industries, Stanford, Spring, CT) and one inch cut from all sides of the core also using a sterile core saw blade. Each median part of a core was placed in a stainless steel core crusher under nitrogen gas and subjected to 1.4×10^4 kPa (20,000 psi) using a hydraulic press. Each portion of crushed core material was passed through a sterilized U.S.A. Standard Testing Sieve No. 40 [0.42 mm (0.0165 inch) openings] to make the inocula more uniform. All analyses were performed in a bacteriological hood containing an atmosphere of nitrogen gas.

2. Enumeration of Microorganisms

Fifty grams of sieved core material was mixed with 50 ml of sterile simulated production water described below that served as the diluent for this and subsequent dilutions. After mixing, 10 ml of the first dilution was transferred to a 90 ml dilution blank contained in a six-ounce prescription bottle. The second dilution was mixed thoroughly before transferring 10 ml to the next dilution blank. Precautions were taken to insure homogeneity in the suspensions prior to sampling, thus, particulate matter was present in all samples.

All work was conducted in a bacteriological hood containing a nitrogen atmosphere at a constant inlet pressure of 10 psi. The absence of oxygen in the atmosphere of the hood was confirmed by gas chromatographic (GC) analysis.

The conventional spread plate technique was employed in some enumeration procedures while the Most Probable Number (MPN) technique[8] was employed in others. All plate counts were performed in triplicate.

Simulated production water used for the core flood experiments was prepared with the following inorganic salts per 50 liters of distilled water.

$CaCl_2$	10.90 g
$MgCl_2$	2.71 g
$BaCl_2$	4.56 g

Na_2SO_4	1.84 g
$NaHCO_3$	34.86 g
NaCl	147.90 g

The pH was adjusted to 7.0 (±0.2) using 10% (v/v) HCl.

The following groups of microorganisms were enumerated.

Total Heterotrophs were enumerated using the conventional spread plate technique and Bacto Plate Count Agar (PCA) obtained from Difco Laboratories, Detroit, MI. Plate counts were conducted under both aerobic and anaerobic conditions with the anaerobic cultures incubated in the BBL Gas Pak® Systems containers. Plates were incubated at the temperature prevailing in the reservoir (32°C).

Oil-utilizing Bacteria were enumerated using the conventional spread plate technique and oil-overlay agar. Incubation was as described for the total heterotrophs. Oil-overlay agar was prepared with simulated production water supplemented with 0.1% KNO_3, 0.038% K_2HPO_4, 1% filter-sterilized crude oil, and 2% Bacto-Agar. After the agar had been poured and had hardened in the petri plates, a thin overlay was added using oil agar prepared with oil-saturated water, but containing no added oil.

Two groups of Methane-producing Bacteria were enumerated, both using the Most Probable Number (MPN) technique (three tubes per concentration of sample). One set of tubes was supplemented with 10 g per liter of sodium formate, while the other set of tubes was incubated under an atmosphere of 80% H_2-20% CO_2 as described by Zeikus[9]. Tubes were incubated at the reservoir temperature (32°C). All tubes were closed with serum stoppers and methane production determined by GC analysis of the atmosphere in the tube.

Denitrifying and Nitrate-reducing Bacteria were enumerated using the Most Probable Number (MPN) technique (three tubes per concentration of sample) and Bacto-Nitrate Broth in test tubes containing Durham fermentation tubes. The tubes were incubated anaerobically for three weeks at the reservoir temperature (32°C). After incubation, tubes showing gas production were recorded as positive for denitrifying bacteria. Spot tests for nitrite were conducted using the sulfanilic acid and *a*-naphthylamine acetate reagents as described in Standard Methods for the Examination of Water and Wastewater [8]. Negative tubes were reexamined after 60 days.

Nitrate-reducing, Hydrocarbon-utilizing Bacteria were enumerated using the Most Probable Number (MPN) technique (three tubes per concentration of sample) and the hydrocarbon-utilizing, nitrate-reducing medium of Rosenfeld[10] but modified by using simulated production water in place of synthetic seawater as follows:

$FeSO_4$	0.1 g
K_2HPO_4	0.5 g
KNO_3	1.0 g

Simulated production H_2O (400%)	25.0 ml
Distilled water	965.0 ml

The reaction mixture was adjusted to pH 7.8 prior to the addition of 1% crude oil (v/v).

After three weeks of anaerobic incubation at the reservoir temperature (32°C), the tubes were examined for the presence of nitrite as described above. Negative tubes were reexamined after 60 days.

Sulfate-reducing, Hydrocarbon-utilizing Bacteria were enumerated using the Most Probable Number (MPN) technique (three tubes per concentration of sample) and the hydrocarbon-utilizing, sulfate-reducing medium described by Rosenfeld [10], but modified by using simulated production water in place of synthetic seawater as follows:

Fe $(NH_4)_2$ $(SO_4)_2 \cdot 6H_2O$	0.1 g
K_2HPO_4	0.5 g
$(NH_4)_2SO_4$	1.0 g
Simulated production H_2O (400%)	25.0 ml
Distilled water	965.0 ml
Crude Oil	10.0 ml

After three weeks of anaerobic incubation at the reservoir temperature (32°C), the tubes were examined for blackening of the agar. Negative tubes were reexamined after 60 days.

Test for Ultramicrobacteria was conducted by crushing fifty grams of core and vigorously mixing it with 200 ml of sterile saline solution (2.5% NaCl, w/v). The suspension then was filtered through a Whatman No. 1 filter paper to remove fines that would interfere with the filtration process. The suspension was immediately filtered through a pre-sterilized membrane filter (0.80 μm) and then through a pre-sterilized 0.45 μm membrane filter to trap normal size bacteria. The filtrate was next filtered through a pre-sterilized 0.22 μm membrane filter. One ml of the filtrate then was added aseptically to a test tube containing 10 ml of Tryptic Soy Broth (TSB) at a final concentration of one-eighth the strength of the original medium. The filters were placed into test tubes containing the same medium and incubated anaerobically at 32°C. Both the filters and filtrates were tested for the presence of viable microorganism weekly.

D. Results of Core Analyses

1. Geological Characterization

A general description of recovered cores is as follows.

Sandstone, grayish brown when dry and brownish gray when wet. The sandstone was a massive fine-grained quartz with less than 10% heavy minerals; well sorted; subrounded to subangular; and moderately well cemented with silica cement.

The sandstone had occasional silty clay clasts, more numerous near the top. The clay clasts were medium light gray when dry and toward the bottom; dark gray when wet and near the top. The clasts were up to 1 inch in diameter.

There were horizontal and vertical fractures present. The fractures and occasional near horizontal silty clay laminae were dark stained (particularly noticeable when wet).

The dark staining in the laminae and fractures, as well as some zones within the sandstone, appeared to be hydrocarbons. The core had a hydrocarbon odor and fluoresced purple from areas that correspond with dark stains.

Most silts and clay laminae as well as clasts were visible in the faces of horizontal breaks in the cores and only occasional clasts noticed elsewhere. Occasional dark stained laminae were noticed throughout.

A typical identification and description of core samples is as follows: Sandstone, buff, fine, grain, well sorted, siliceous, laminated, dolomite. X-ray diffraction analysis indicated the core was preliminary quartz (90%) with some 4% dolomite. The clay fraction consisted of 2% kaolinite and 3% mixed layer clay. Some traces of siderite ($FeCO_3$) were present in some samples.

X-ray diffraction Analysis	
Quartz	90%
Dolomite	4%
Kaolinite	2%
Mixed layer clay	3%
Siderite	<1%

For more detailed geological characterization of recovered cores, refer to Supplement[11].

2. Petrophysical Characterization of Recovered Core Samples

Core sample porosity varied from 7 to 19 percent. Core sample permeability varied much more drastically from 1 to 198 md. Representative data are given in Table 1.

Connate water saturation was around 17 percent and irreducible oil saturation was between 34-45 percent (see Figures 4 and 5 for typical relative permeability curves for oil-water and gas-oil experiments). The relative permeability curves and contact angle photographs suggest that the core samples were oil-wet at the time of testing. For more detailed information on petrophysical characterization of recovered cores refer to Supplement[11].

Table 1.
Porosity and permeability of collected core samples.

No.	Depth. Feet	Porosity pc	Permeability, md gas	Permeability, md liquid	Grain Density gr/cc
1	2333	18.90	24.80	11.00	2.35
2	2332	18.50	25.90	8.88	NA
3	2332	16.25	88.00	36.00	NA
4	2332	15.16	108.00	36.00	2.54
5	2331	15.16	4.70*	9.60*	NA
6	2330	NA	30.20	9.22	NA
7	2330	NA	21.38	8.82	2.25
8	2330	15.89	15.89	3.79	NA
9	2330	NA	24.77	3.51	2.41
10	2330	NA	14.79	10.96	NA
11	2329	15.16	30.20	9.00	2.73
12	2329	15.16	18.60	3.60	NA
13	2329	15.16	19.80	10.10	NA
14	2329	16.25	122.00	66.00	2.44
15	2329	15.60	108.00	36.00	NA
16	2329	16.25	88.00	36.00	NA
17	2323	19.79	26.80*	41.78*	NA
18	2323	14.98	42.00*	41.77*	2.81
19	2323	NA	39.00	41.00	2.27
20	2323	NA	26.80	8.10	2.30

*These data may not come from the same core cut.

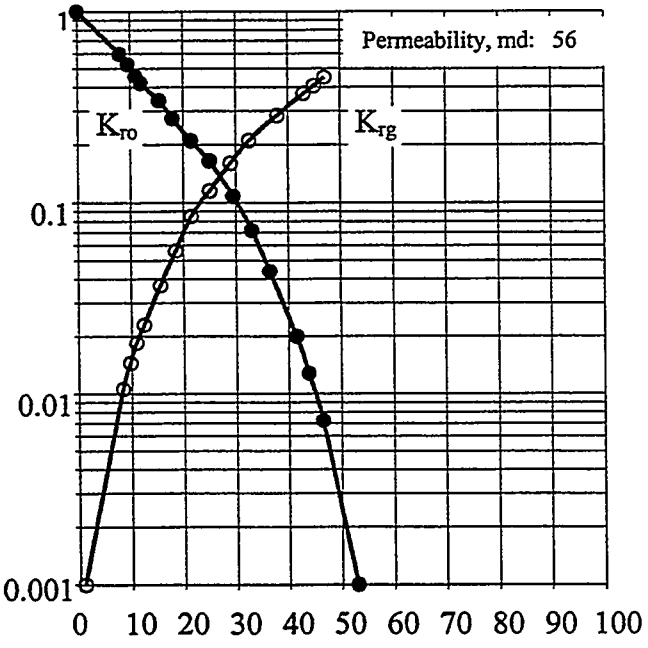


Figure 4. Relative permeability as a function of gas saturation.

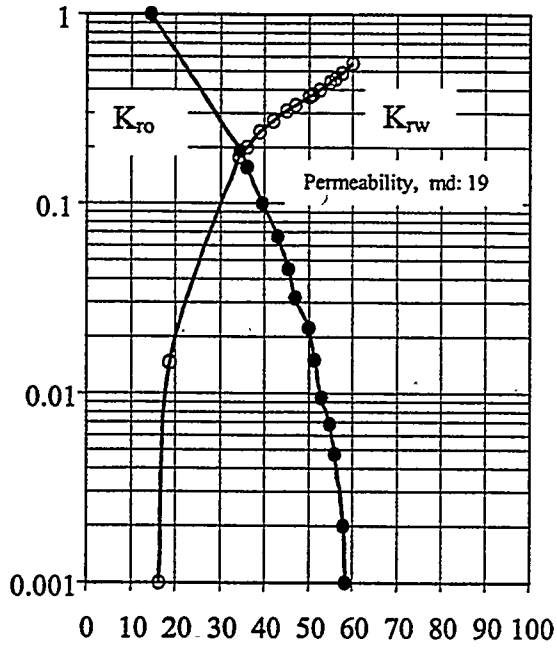


Figure 5. Relative permeability as a function of water saturation.

3. Microbiological Characterization

Each core was divided into three portions, (top, middle, and bottom) crushed, and analyzed for total heterotrophs and oil-utilizing bacteria by the conventional spread plate technique (as shown in Table 2) and for five physiological groups of microorganisms using the MPN technique (as shown in Table 3). It is interesting to note that there were no sulfate-reducing microorganisms (SRB) in any portion of the core. This was particularly surprising in that SRB's have been reported in the literature as the most prevalent organism in oil reservoirs, and SRB's had been recovered from fluids from other wells in this field. Thus, the results suggest that the area of the reservoir in which this well was drilled had not been swept by the waterflooding. It is also interesting to note that in a previous study[12] no SRB's were found in live cores obtained from wells drilled in areas of 13 oil fields not impacted by EOR processes[13].

Table 2.
Aerobic and anaerobic heterotrophs and oil-utilizing microorganisms in samples of core from newly drilled well.

	PCA		Oil Agar	
Core	Aerobic	Anaerobic	Aerobic	Anaerobic
Top	1	0.3	<1.0	<1.0
Middle	43	2.0	193.0	<1.0
Bottom	36	2.0	0.3	<1.0

Numbers are No. of bacteria/g of core.
PCA = Plate Count Agar

Table 3.
Different physiological groups of microorganisms in the core from the newly drilled well.

Core	Methanogen CO_2:H_2 Broth	Methanogen Formate Broth	HC-utilizing NO_3-reducing Broth	HC-utilizing SO_4-reducing Broth	Difco Nitrate Broth
Top	4.6	<0.6	<0.6	<0.6	18.6
Middle	4.6	48.0	<0.6	<0.6	>220.0
Bottom	7.8	>220.0	<0.6	<0.6	18.6

Numbers are No. of bacteria/g of core.

No evidence of ultramicrobacteria (UMB) was found in any of the cores.

E. Formulation of Feeding Regime

1. Preparation of Core Plugs

Cores were removed from the GasPak® containers under a nitrogen atmosphere and two adjacent core plugs were cut radially from each core, one to serve as the test core and one as the control core. The plugs were 7.6–10.2 cm (3-4 inches) long and 3.8 cm (1.5 inches) in diameter. While still under a nitrogen atmosphere, each plug was inserted immediately into a special heat shrink plastic tube. The plastic wrap shrank as it was heated and wrapped tightly around the core. An entry and an exit port were placed on opposite ends of the core. These ports contained grooves for the reduction of end effects and for more homogeneous distribution of flowing fluids. The entire assembly then was inserted into a thick rubber sleeve [Viton Neoprene Sleeve, 3.8 cm (1.5 inches) diameter, with a 6 mm (0.24 inch) wall]. The ends of the entry and exit ports were fitted with rubber tubing and clamped shut. Both ends were completely sealed with high strength epoxy glue. The glue was allowed to harden for 24 hrs before the cores were used. Figure 6 is a diagrammatic sketch of the assembled core. Figures 7 and 8 are photographs of the cores.

2. Treatment of the Cores

Initially, simulated production water, contained in a five-liter carboy, was allowed to flow through the core. The carboy was situated approximately 1 m above the core and this hydrostatic head corresponds to 13.24 kPa (1.92 psi) and constituted the total pressure applied to the influent. The water was allowed to flow through a core plug for 48 hrs after which time experimentation commenced. Control cores received simulated production water only while the test cores received simulated production water containing added nutrients (nitrate as 0.06% potassium nitrate and orthophosphate as 0.04% disodium hydrogen phosphate).

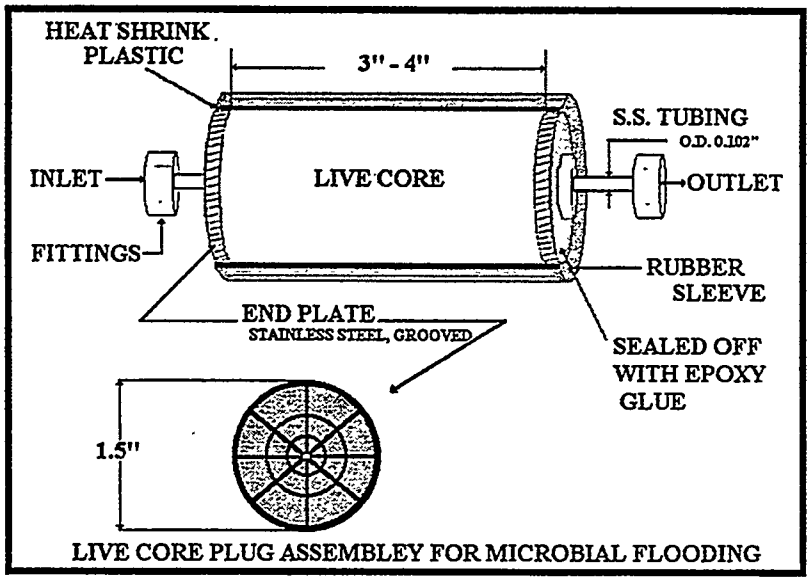


Figure 6. Live core assembly.

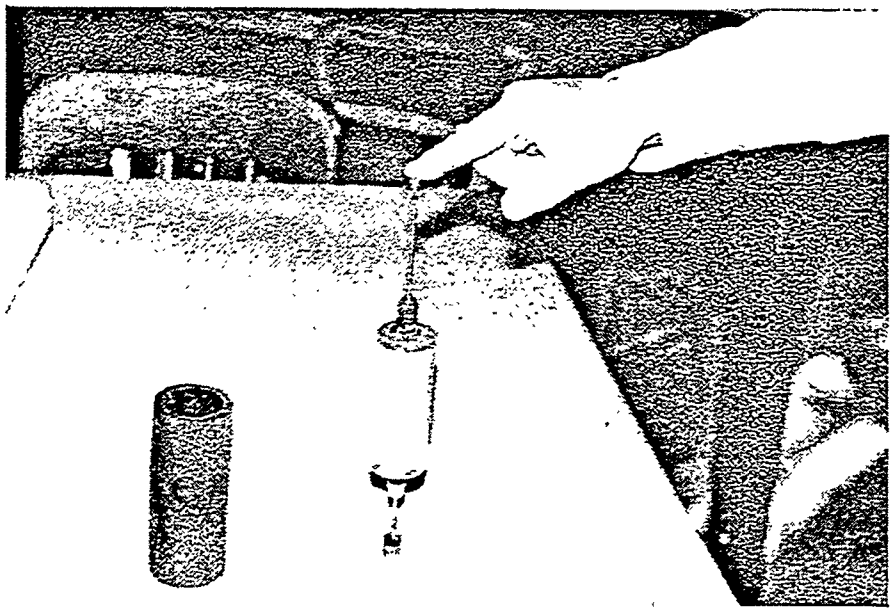


Figure 7. Photograph of core in plastic wrap next to the rubber sleeve.

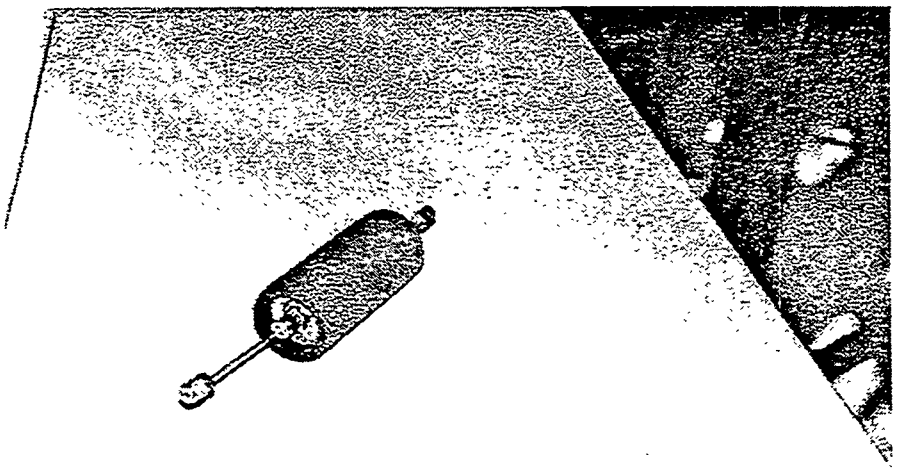


Figure 8. Photograph of completely assembled core plug.

3. Analyses of Effluent from Core Plugs

Fluid volume, pH, and microbial content were measured and recorded periodically for all cores and observations made as to the presence of oil in the effluent. Plate counts were conducted on selected samples using Bacto Plate Count Agar prepared with simulated production water. Plates were incubated for 72 hrs at 32°C under aerobic conditions or two weeks under anaerobic conditions.

4. Core Flood Experiments

The first series of core flood experiments were carried out as described above and as would be expected, flow through the cores varied from one core to another. The pH of the effluent from both cores ranged from 7.4 to 8.4 and the microbial content remained constant at about 10 organisms per ml for both the control and the test cores. It should be pointed out that most microorganisms grow attached to solid surfaces and therefore, the number of microbes in the effluent is not a reflection of the number in the cores.

The control cores showed a steady increase in flow rate while the flow rate in test cores decreased with time. In a typical experiment, oil was found in the effluent of the control core only once as shown in Figure 9, while in the test core, oil was found six times (day 11, 13, 14, 16, 19, and 25) as shown in Figure 10.

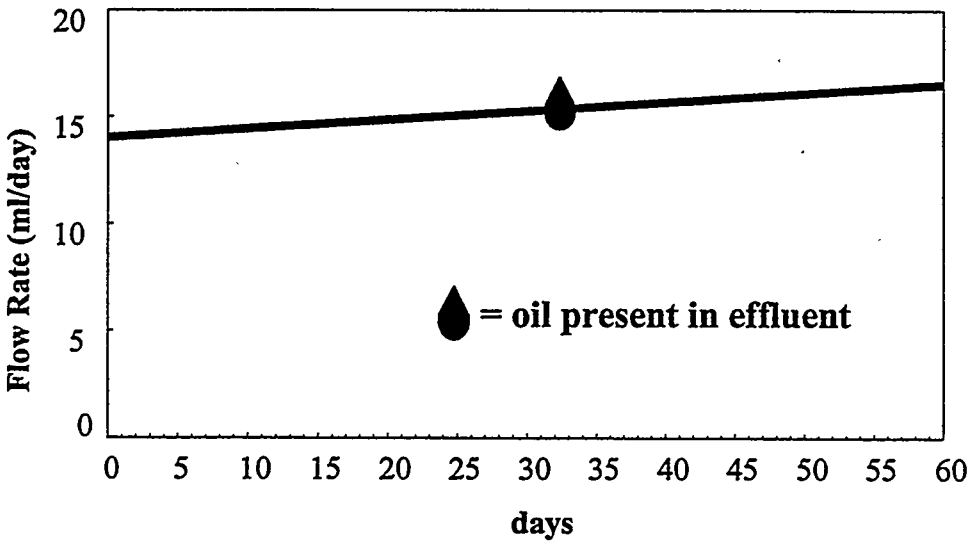


Figure 9. Flow of simulated production water through control core in experiment 2.

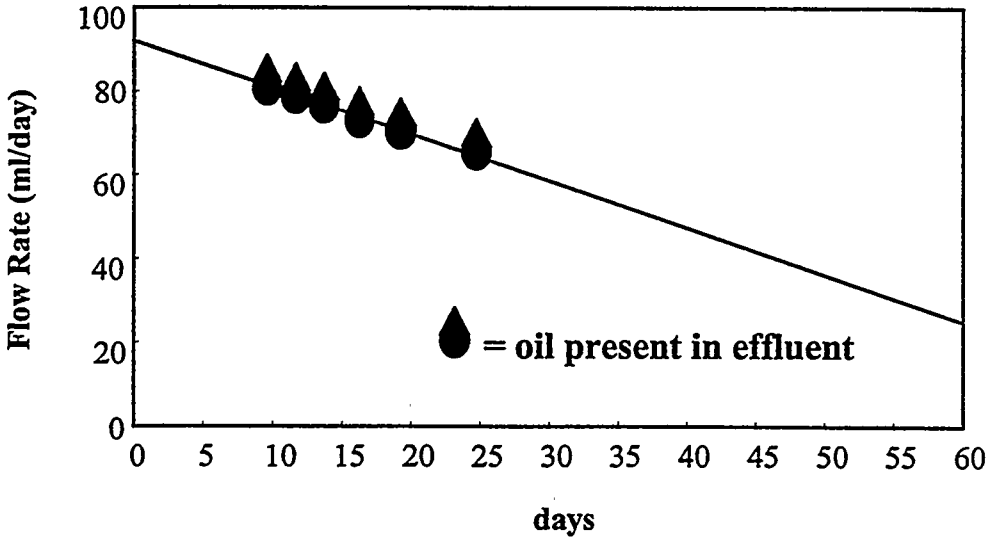


Figure 10. Flow rate of simulated production water containing potassium nitrate and disodium hydrogen phosphate through test core in experiment 2.

After the experiment was repeated three times, it was concluded that the addition of nitrate and orthophosphate should result in the stimulation of the *in situ* microflora with the subsequent generation of biomass that would decrease the flow in the pore throats of the reservoir formation. This decrease in flow through the main channels in the reservoir should

divert injection water to the less permeable areas of the formation, thereby increasing the sweep efficiency of the waterflooding operation.

Additional core flooding experiments were conducted using molasses as a microbial nutrient in addition to potassium nitrate and sodium orthophosphate. In a representative experiment, another set of core plugs was prepared as above. The control core received simulated injection water every day while the test core received simulated injection water plus nutrient supplements on the following schedule. Molasses in a concentration of 1% (v/v) on day 1, potassium nitrate in a concentration of 0.06% (w/v) on day 3, and disodium hydrogen phosphate in a concentration of 0.04% (w/v) on days 5, 7, and 9. This schedule was repeated every ten days for the duration of the experiment. As may be observed in Figure 11, the flow rate constantly increased in the control core plug.

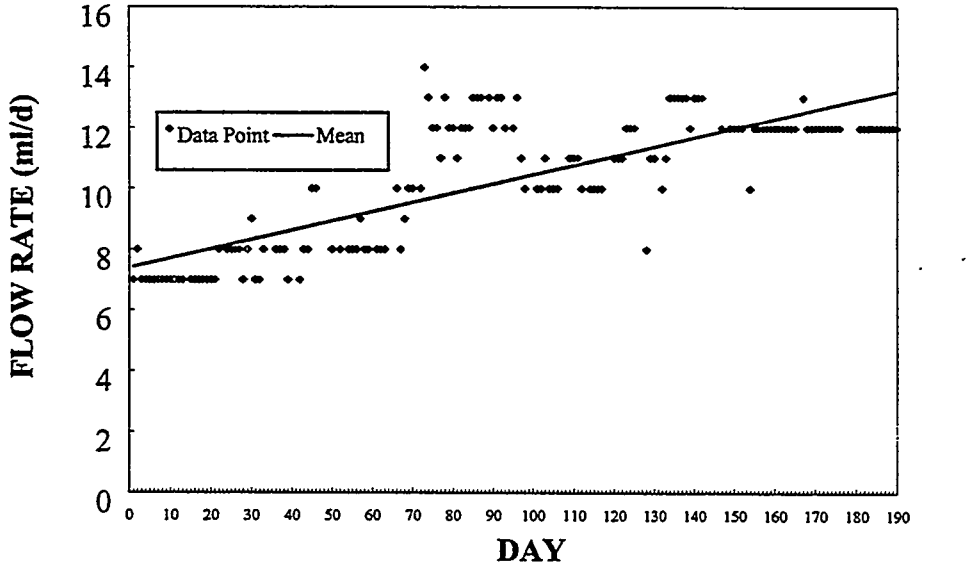


Figure 11. Flow rate of simulated injection water through control core plug.

Contrariwise, the flow rate of injection water through the test core decreased with time (see Figure 12). After 61 days, the flow rate was increased by increasing the pressure on the influent (flushed) thereby increasing the flow of injection water through the core plug. Once again, flow rate decreased with time and the core plug was flushed a second time. This cycle was repeated one more time during the 187-day duration of the experiment. These data suggest that permeability profile modification could be accelerated by the addition of small amounts of molasses to the feeding regime.

The above experiment was repeated using the actual injection water from the North Blowhorn Creek Oil Field instead of simulated injection water. The results of this experiment paralleled those of previous experiments.

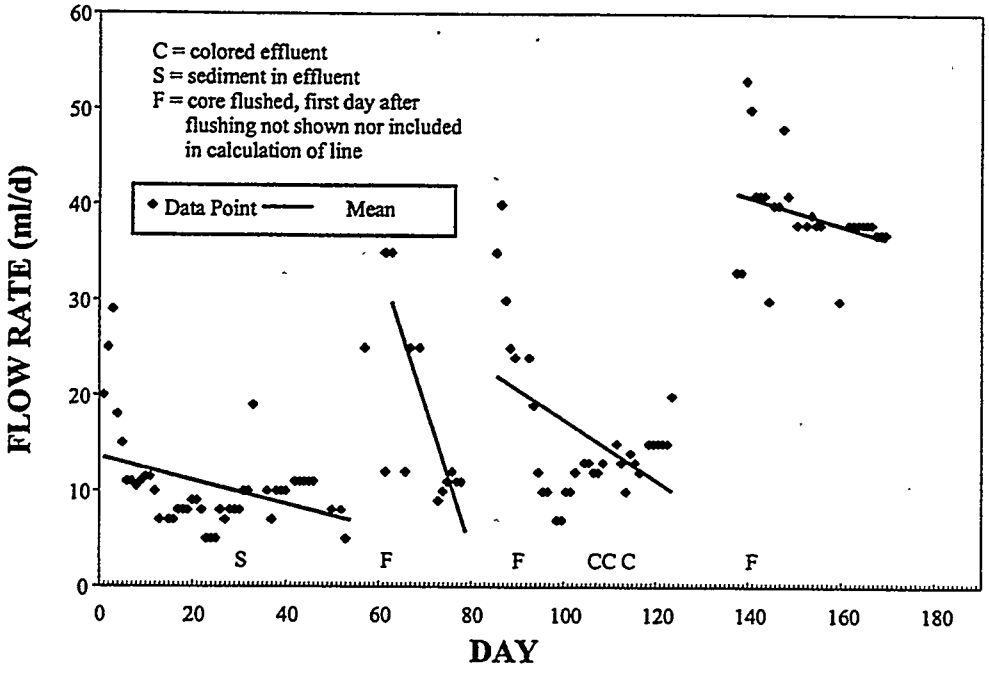


Figure 12. Flow rate of simulated injection water containing nutrients through test core plug.

F. Tracer Study

Early in the planning stages for the project, the first test well pattern was chosen for a tracer study because it had been observed in the field that the NBCU 2-14 No. 1 injection well seemed to be very well connected to the 2-13 No. 1 hydraulically. The 2-14 No. 1 allowed injection of relatively high rates, and the 2-13 No. 1 produced high fluid rates and was over pressured. It was theorized that the movement of water from the injector to producer would be quicker than in any other injection pattern. However, to quantify the time for fluid to travel from injector to the producers in the first pattern, the decision was made to conduct a radioactive tracer survey. If the travel time could be established, then some time frame for the effects of microbial activity to become detectable could be established.

On April 27, 1994, 2 Ci of tritiated water was injected into the 2-14 No. 1 well. Weekly and then monthly sampling of water from the four test pattern producing wells was carried out. No trace of the material was detected by the laboratory analysis of the water samples until October 12 when 14 pCi/ml was detected in 2-13 No. 1. On November 9, 1994 the concentration of tritium in the sample from well 2-13 No. 1 had increased to 41 pCi/ml and continued to be for the entire monitoring period which ended in March 1996. On October 18, 1996 1.6 $\pm$1.0 pCi/ml was detected in the sample obtained from well 11-3 No. 1 and continued to be present

throughout the monitoring program. On November 9, 1994, 1.9±0.3 pCi/ml was detected in the sample from well 2-15 No. 1 but was not found in any subsequent samples. Thus, on the basis of the tracer study evidence of microbial activity could not be expected to be detectable in less than seven months and probably closer to a year after initiation of nutrient injection.

G. Baseline Studies

1. Methods

Fluids from both injector wells and producer wells in all patterns were collected monthly in 5.7-liter (1.5 gallon) containers and brought to the laboratory for analysis. Oil and water were separated and a portion of the oil sample analyzed for its aliphatic profile by gas chromatography (GC). The remainder of the oil sample was used for measurement of gravity, viscosity, and interfacial tension (IFT). Additionally, the water samples were analyzed for surface tension (ST), pH, microbial content, and several inorganic ions. Production rates of fluids (oil, gas, and water) from the producer wells in all patterns were measured weekly by the field lease operator. These rates were plotted vs time to exhibit well production potential. For the most part, these graphs were consistent with actual plots of well production (based on sales) vs time. However, variations between the two plots were caused by well down time, freeze, or other production problems in which case these plots showed greater potential production than the actual production obtained (see Supplement [11]).

Acquisition of Fluid Samples. Produced fluids were collected monthly from the wellhead of each producing well in all patterns. Injection make-up water samples were periodically collected from a deep well on site. Samples of injection water, which were a mixture of all produced waters from all the wells in the field, were collected monthly.

Enumeration of Microorganisms. Ten ml of a water sample was mixed with 90 ml of the distilled water, contained in a six-ounce prescription bottle. This dilution was examined using the conventional spread plate technique to enumerate total heterotrophs and oil-utilizing bacteria. All plate counts were performed in triplicate as described in the section III C1 above.

Chemical Methods

The following chemical tests were performed on produced water.

> Orthophosphate was determined using the Ascorbic Acid Reduction method as given in the Standard Methods for the Examination of Water and Wastewater[8].
>
> Nitrate-nitrogen was determined using the Cadmium Reduction Method as given in the Standard Methods for the Examination of Water and Wastewater [8].

Sulfate was determined using the Barium Chloride Method as given in the Standard Methods for the Examination of Water and Wastewater [8].

Potassium was determined using the Tetraphenylboron Method as given in the Standard Methods for the Examination of Water and Wastewater[8].

Sulfide was determined using the Methylene Blue Method as given in the Standard Methods for the Examination of Water and Wastewater [8].

Chloride was determined using the Argentometric Method as given in the Standard Methods for the Examination of Water and Wastewater[8] .

Calcium carbonate was determined using the EDTA Titrimetric Method as given in the Standard Methods for the Examination of Water and Wastewater [8].

Gas Chromatographic Analyses.

Analysis of oil samples collected from test and control producing wells was performed on a Varian® 3300 single column gas chromatograph (GC). The column was a J&W DB-1 30 x 0.53mm. Other GC operating settings are as follows.

Initial Col. Temp,°C	40.00
Initial Col. Hold Time, min	2:00
Program Final Col. Temp.°C	290.00
Program Col. Rate in ml/min	15.00
Program Col. Hold Time, min	5:00
Injector Temp.°C	290.00
Detector Temp.°C	300.00
FID B Initial Att	1.00
FID B Initial Range	10.00
Completion, min	35.00

The GC was connected to a desktop computer supported by Varian® GC Star Chromatograph version 4.0. All peaks were relayed into the computer and were saved in their entirety for future reference.

The carrier gas, helium, was employed at a flow rate of 35 ml/min, air pressure 414 kPa (60 psig), and the hydrogen running pressure 414 kPa (60 psig). Identification of paraffinic components was achieved by comparison of the retention time of peaks on the chromatogram to the retention time of standard samples. The area under the curves for different peaks was normalized. The standard sample used was ASTM Method D2287 Calibration Mixture.

The samples were prepared for GC analysis as follows. Using an Eppendorf pipette, 100 µl of oil was placed in a five-ml beaker containing two ml of methylene chloride. The contents

of the beaker were poured over sodium sulfate (to remove water if present) and the filtrate placed in a two ml crimp-top vial with a teflon septum.

Petrophysical Analyses

The following characteristics of produced fluids from selected wells, test as well as control, were measured.

- Gravity (API) of produced oil (at room temperature)
- Viscosity of produced oil (at reservoir temperature)
- Interfacial tension (IFT) for produced and separated oil-water system
- Surface tension (ST) of air-water systems in IFT
- pH of produced water

2. Results

Since the baseline values were employed in the monitoring of the field demonstration, the results of these analyses are included in Section IV G1, 2, and 3 of the next section of this report.

IV FIELD TRIAL

A. Design of Skid for Nutrient Injection

After completion of the laboratory core flood experiments, the results were scaled up to field operating volumes which became the design basis for the nutrient skids (see Figure 13). It was determined that each injection skid needed the ability to mix and pump 380–1135 liters (100-300 gallons) of water containing 23–180 kg (50-400 lb) of chemicals per day at a pressure of 8275 kPa (1200 psi). The ability to vary the pump rate over a wide range was required as well as the ability to maintain a precisely metered rate. With the exception of the molasses, the other nutrients were packaged dry in 23 kg (50 lbs) bags, so the ability to mix the chemicals and know that all went into solution was required. The skid was designed for simple maintenance and operation by the field lease pumpers. A small storage area to keep unused chemicals dry also was required.

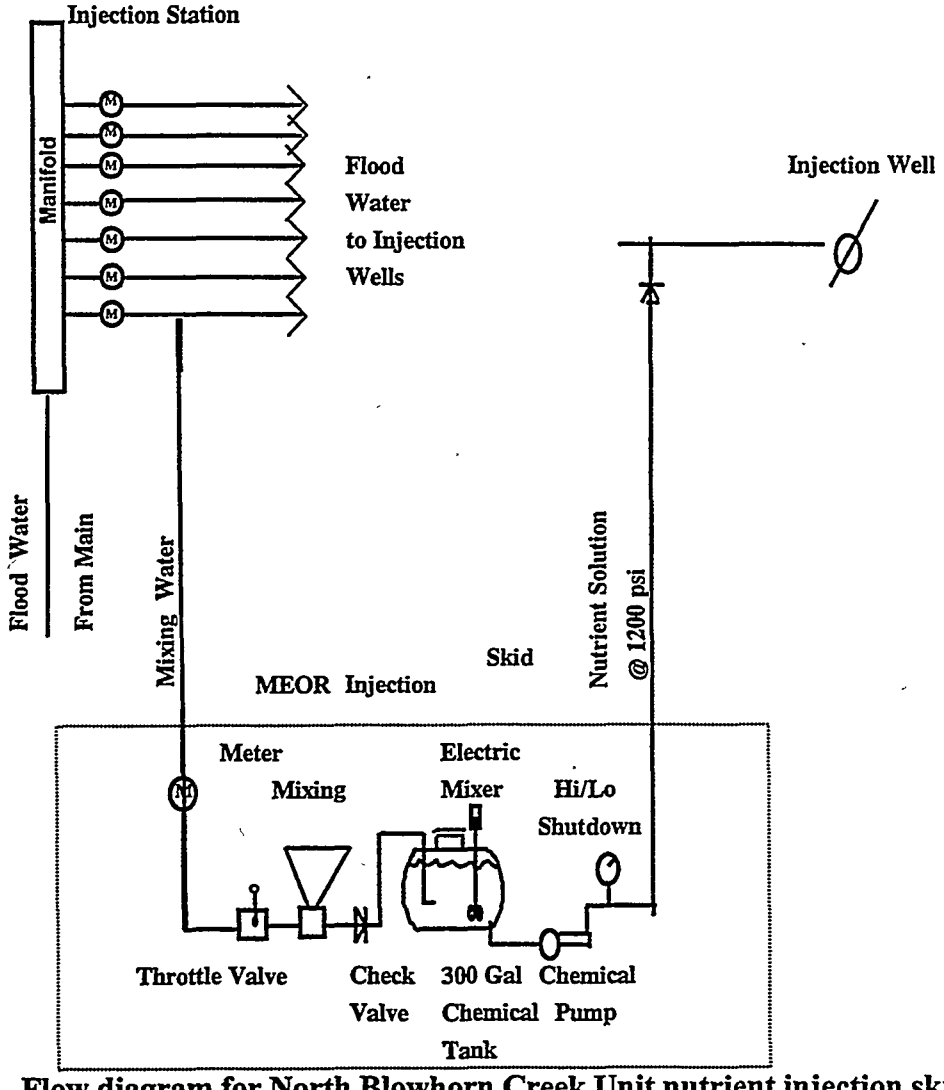


Figure 13. Flow diagram for North Blowhorn Creek Unit nutrient injection skid.

Based upon these requirements, the skid shown in (Figure 14) was constructed. It consisted of an oil field type skid with a metal roof and storage cabinet in one end. A mixing hopper was fabricated to make use of the 8275 kPa (1200 psi) waterflood water as a mixing jet for the dry sack chemicals. The mixture was stored in a 1135 liter (300 gallon) plastic tank which allowed direct observation and sampling of the solution. The tank contained an electric stirrer, which was generally run for a couple of hours after each batch of chemical was mixed to ensure that all of the chemical dissolved. The mixture was pumped downhole by a large air powered chemical pump which had a variable speed with precise displacement at any given speed. Subsequent designs switched to a small triplex pump driven by a DC electric motor with speed control. A high/low pressure switch shuts down the pump if the main waterflood pump quits or a line ruptures. The supply water line came directly from the waterflood line near the wellhead and the discharge line tied into the well just upstream of the wellhead.

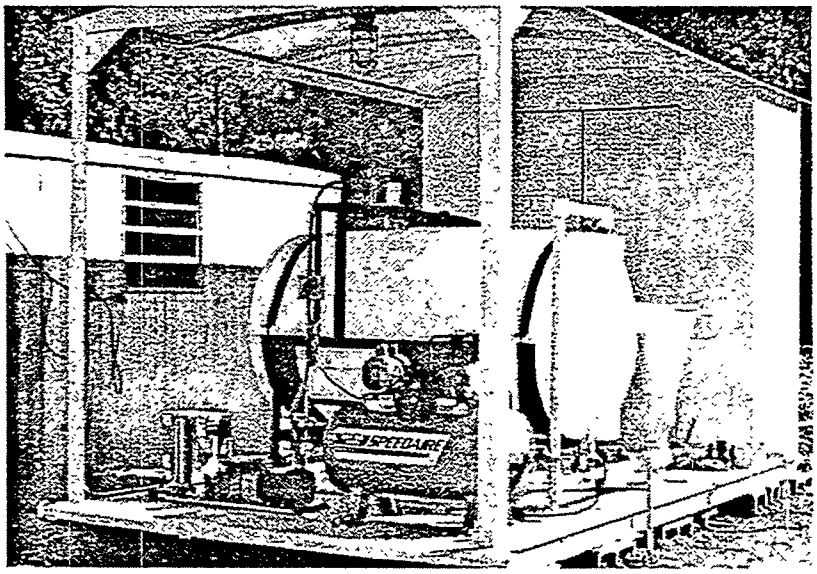


Figure 14. Picture of skid.

B. Design of Field Trial

1. Test Patterns for Field Demonstration

Figure 15 shows the locations of the wells in the four test and four control patterns.

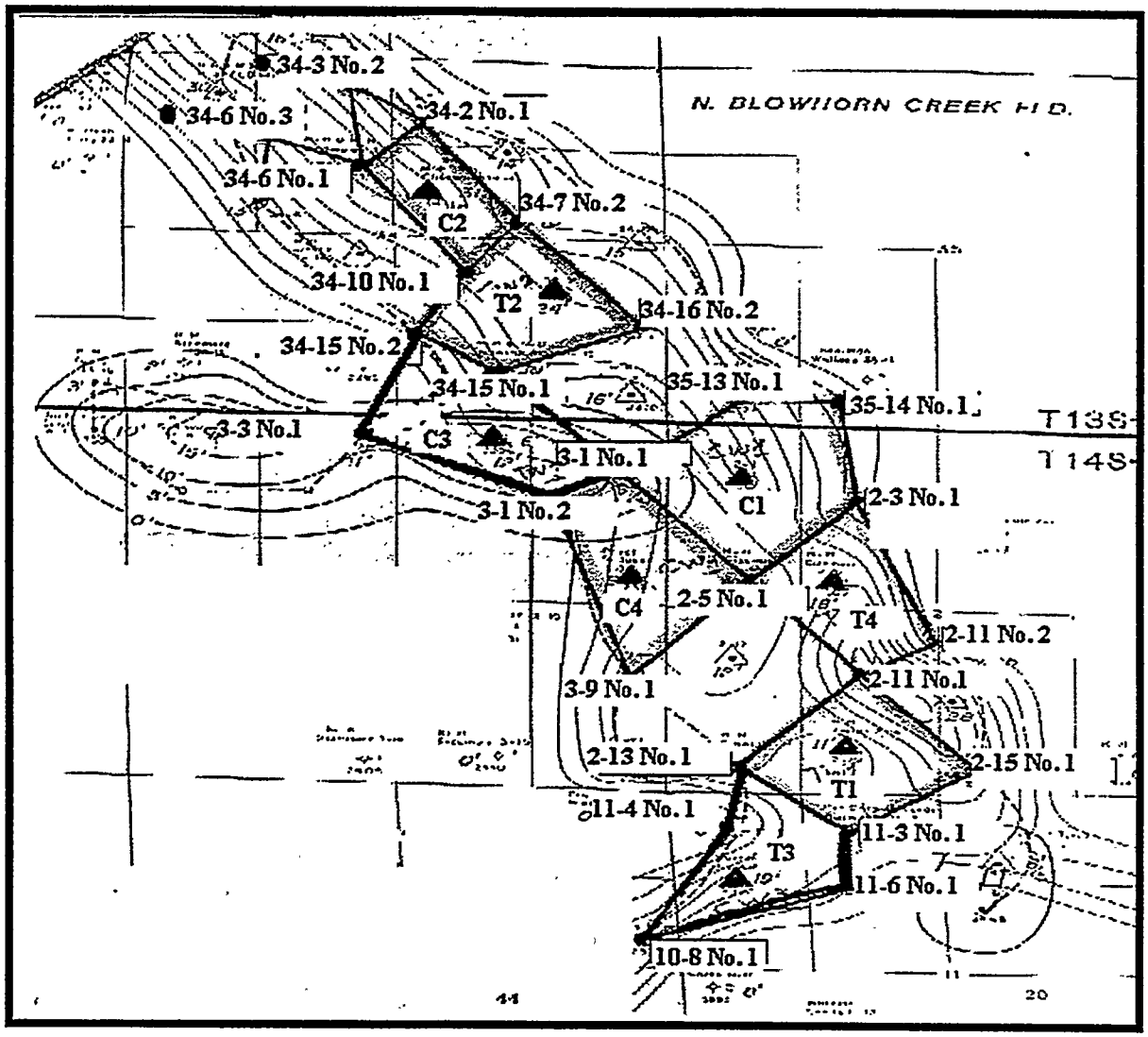


Figure 15. Isopach of NBCU oil field showing locations of wells in the four test and control patterns.

The wells included in the patterns are as follows:

TP No. 1
Injection-Production Pattern:

Injection Well:	NBCU 2-14 No. 1
Production Wells:	NBCU 2-11 No. 1*
	NBCU 2-15 No. 1
	NBCU 11-3 No. 1*
	NBCU 2-13 No. 1*

CP No. 1 (Control Set)

Injection Well:	NBCU 2-4 No. 1
Production Wells:	NBCU 35-13 No. 1
	NBCU 35-14 No. 1
	NBCU 2-3 No. 1*
	NBCU 2-5 No. 1*
	NBCU 3-1 No. 1*

TP No. 2

Injection-Production Pattern:

Injection Well:	NBCU 34-9 No. 2
Production Wells:	NBCU 34-7 No. 2*
	NBCU 34-16 No. 2
	NBCU 34-15 No. 1*
	NBCU 34-15 No. 2*
	NBCU 34-10 No. 1*

CP No. 2 (Control Set)

Injection Well:	NBCU 34-7 No. 1
Production Wells:	NBCU 34-2 No. 1
	NBCU 34-6 No. 1
	NBCU 34-7 No. 2*
	NBCU 34-10 No. 1*

TP No. 3

Injection-Production Pattern:

Injection Well:	NBCU 11-5 No. 1
Production Wells:	NBCU 10-8 No. 1
	NBCU 11-6 No. 1
	NBCU 11-4 No. 1
	NBCU 11-3 No. 1*
	NBCU 2-13 No. 1*

CP No. 3 (Control Set)

Injection Well:	NBCU 3-2 No. 1
Production Wells:	NBCU 3-3 No. 1
	NBCU 3-1 No. 1*

NBCU 3-1 No. 2*
NBCU 34-15 No. 1*
NBCU 34-15 No. 2*

TP No. 4

Injection-Production Pattern:

Injection Well:	NBCU 2-6 No. 1
Production Wells:	NBCU 2-11 No. 2
	NBCU 2-3 No. 1*
	NBCU 2-5 No. 1*
	NBCU 2-11 No. 1*

CP No. 4 (Control Set)

Injection Well:	NBCU 3-8 No. 1
Production Wells:	NBCU 3-1 No. 1*
	NBCU 3-1 No. 2*
	NBCU 3-9 No. 1
	NBCU 2-5 No. 1*

*Indicates wells included in more than 1 test or control pattern.

2. Feeding Regime

The test pattern No. 1 injector well (NBCU 2-14 No. 1) was injecting 76–80 m^3 (480-500 barrels) of water per day. Based on this rate of injection and the results obtained from the core flood experiments, it was decided to employ the addition of potassium nitrate at a concentration of 0.12% (w/v) and disodium hydrogen phosphate at a concentration of 0.034% (w/v). The nutrients were mixed in much higher concentrations on the skids (described below) and injected at such rates that the entire amount of injection water during a 24-hour period contained the above designated concentrations. In order to neutralize the effect of an increased pH of the injection water due to the phosphate addition, two gallons of 10% HCl(v/v) were added to each tank of phosphate solution. Subsequently, monosodium dihydrogen phosphate was substituted, thus obviating the need for adding the 10% HCl.

The following injection schedule was formulated on the basis of a waterflood injection rate of 76 –80 m^3/day (480-500 BWPD) in injector well NBCU 2-14 No. 1 (see Table 4).

Table 4.
Feed and feeding regime from November 1994-April 1996.

	PATTERNS			
NUTRIENTS	1	2	3	4
KNO_3	0.12% (w/v) Mondays	0.12% (w/v) Mondays	same as 1	same as 2
NaH_2PO_4	0.034% (w/v) Wednesday Fridays	0.034% (w/v) Fridays	same as 1	same as 2
MOLASSES	None	0.1% (v/v) Wednesdays	same as 1	same as 2

Nutrient Pumping Schedule

Monday - 91 kg (200 lbs, 4 bags) of potassium nitrate were mixed with 757 liters (200 gals) of water and pumped into the well in as close to 24 hrs as possible.

Tuesday - No chemical was pumped, but the tanks were washed out and the washings pumped down the well during the morning.

Wednesday - 45 kg (100 lbs, 2 bags) of disodium hydrogen phosphate and 7.57 liters (2 gals) of 10% HCl were mixed with 757 liters (200 gals) of water and pumped down the well in as close to 24 hrs as possible.

Thursday - No chemical was pumped but the tanks were washed out and the washings pumped down the well during the morning.

Friday - 45 kg (100 lbs, 2 bags) of disodium hydrogen phosphate and 7.57 liters (2 gals) of 10% HCl were mixed with 757 liters (200 gals) of water and pumped down the well in as close to 24 hrs as possible.

Saturday - No chemical was pumped but the tanks were washed out and the washings pumped down the well during the morning.

Sunday - No chemical added.

The above schedule was repeated each week for test patterns 1 and 3. The same concentrations were employed in test patterns 2 and 4 except that 0.1% molasses (v/v) was being added on Wednesdays instead of disodium hydrogen phosphate and HCl.

This project was initiated in January of 1994. The starting injection dates of nutrient additions to the test injectors in each test pattern were November 21, 1994 for test pattern 1; February 27, 1995 for test pattern 2; January 16, 1995 for test pattern 3; and February 27, 1995 for test pattern 4.

C. Modification of Microbial Feed and Feeding Regime

After a careful evaluation of the field results and additional core flood experiments conducted in the laboratory, it was decided to modify the feed and feeding regimes as shown in Table 5.

Table 5.
Feed and feeding regime from April 1996-June 1997.

	PATTERNS			
NUTRIENTS	1	2	3	4
KNO_3	0.12% (w/v) Mondays	same as before	same as before	0.06% (w/v) Mondays
NaH_2PO_4	0.034% (w/v) Wednesdays	same as before	same as before	0.017% (w/v) Wednesdays
MOLASSES	0.2% (v/v) Fridays	same as before	same as before	0.3% (v/v) Fridays

D. Drilling of Three New Wells

Three new wells were drilled into the Carter formation sand during the Fall of 1996. The purpose of the three wells was to help evaluate the nutrient-induced *in situ* growth of microorganisms by analysis of recovered core samples and produced fluids. The locations of the wells are shown in Figure 16.

The first well drilled was the NBCU 2-5 No. 2 which started drilling on October 11 and reached a total depth of 701 m (2300 ft) on October 17. The well encountered 7.3 m (24 ft) of net Carter sand between 668 and 676 m (2192 and 2218 ft) and 13.1 m (43 ft) of core were recovered. The core analyses indicated that, as a general rule, the lower permeability rock retained a higher oil saturation while the high permeability rock was better swept resulting in a lower oil saturation. Visual observation of the core indicated much remaining oil in the low permeability rock. The well was cased for production, perforated from 668.4 to 676.0 m (2193 to 2218 ft) and fracture stimulated. Rod pumping equipment was installed and the well was placed on production. Initial production was 0.9 m^3/day oil (6 BOPD) with 27.7 m^3/day water

(174 BWPD). This production rapidly declined to 0.2 m^3/day oil (1 BOPD) with 27.7 m^3/day water (174 BWPD) by January 1998. The well is currently shut-in due to uneconomic rate of oil production.

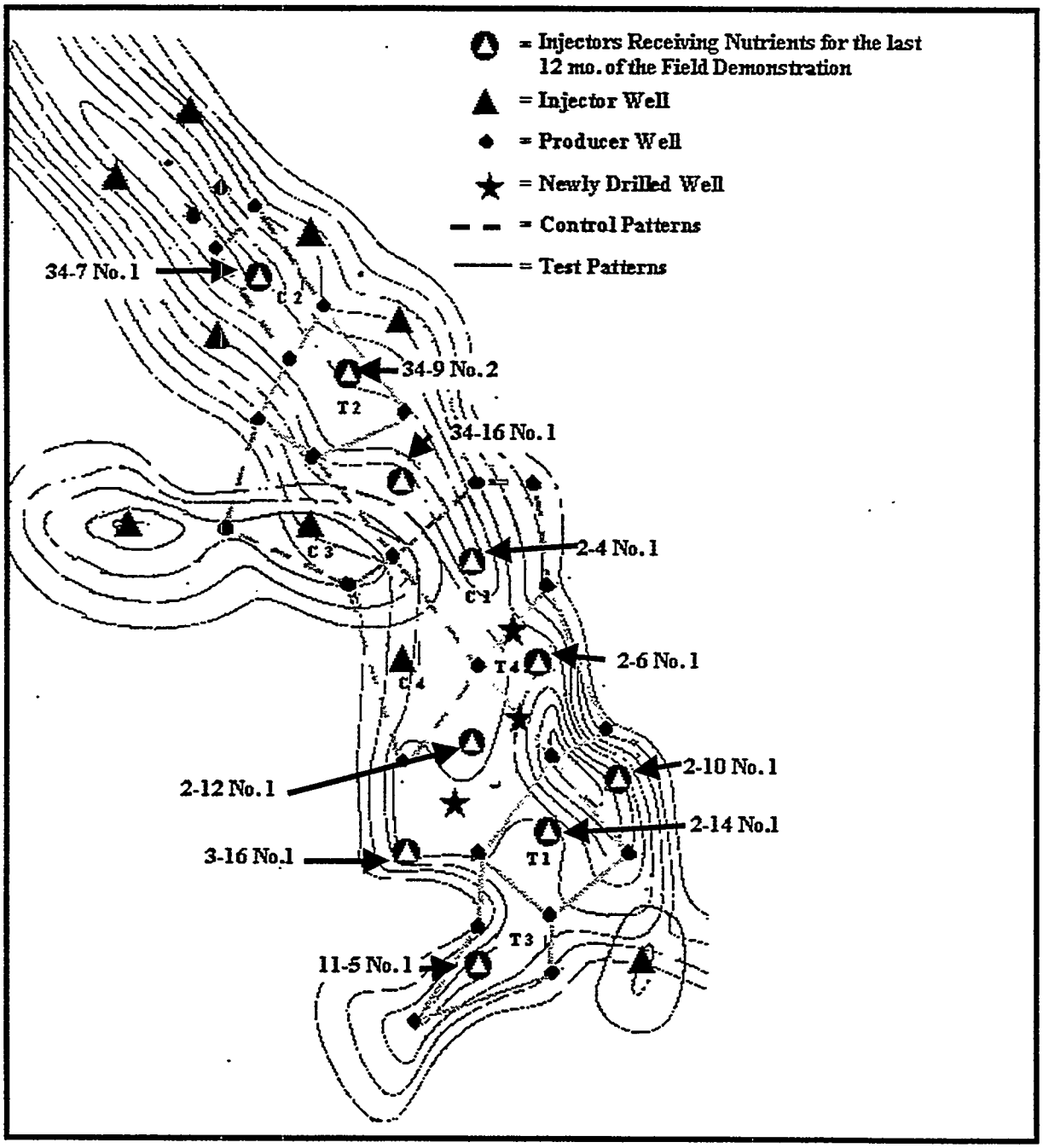


Figure 16. Locations of three new wells and injectors receiving nutrients during the final 12 months of the field demonstration.

The second well drilled was the NBCU 2-13 No. 2 which started drilling on October 22 and reached a total depth of 703 m (2305 ft) on October 30. The well encountered 6.4 m (21 ft) of net Carter sand between 664 and 672 m (2180 and 2205 ft) and 9.7 m (32 ft) of core were recovered. The core analyses indicated much higher permeability in the upper ten feet of the sand than in the lower portion. As in the previous well, the higher permeability rock generally had lower oil saturation than the lower permeability rock, which was harder to sweep by waterflood. Visual observation of the core indicated much remaining oil, as was observed in the previous well. The well was cased for production and perforated from 665-668 m and 669-670 m (2182-2192 ft and 2195-2199 ft). A packer and tubing were run and the well was swab tested at a rate of 76 m^3 (480 bbls) of fluid per day with 15-25% oil. Because the well initially swabbed at a high fluid rate, no fracture stimulation was performed. Rod pumping equipment was installed and the well was placed on production. Initial production was 2.9 m^3/day oil (18.5 BOPD) with 1.7–4.5 m^3/day water (11-28 BWPD). This production gradually declined to 1.6 m^3/day oil (10 BOPD) with 3.5 m^3/day water (22 BWPD) by July 1998.

The third well drilled was the NBCU 2-11 No. 3 which started drilling on November 6 and reached a total depth of 703 m (2306 ft) on November 13. The well encountered 11 m (36 ft) of Carter sand between 659.6 and 670.6 m (2164 and 2200 ft). The sand was much thicker than anticipated. Previous maps had indicated only 5.5 m (18 ft) of sand at this location. A 9.7 m (32 ft) core was recovered which revealed significant remaining oil saturation, along with some portions which had obviously been swept by the waterflood. It was believed the water swept sections would provide the best opportunity to observe microbial growth as a result of nutrient injection into the NBCU 2-6 No. 1 well situated about 152 m (500 ft) north of this well. The well was cased for production, perforated from 659.6 to 670.6 m (2164 to 2200 ft), a packer and tubing run, and the well was fracture stimulated. The well flowed without any stimulation for several months and then was put on rod pump in April 1997. Due to the well's close proximity to the 2-6 No. 1 injector, it produced a high rate of water and never produced oil at a commercial rate.

E. Analysis of Cores

Five sections of core from each of the three newly drilled wells were tested for nitrate ions and orthophosphate ions. Nitrate ions were present in 4, 3, and 5 sections of core samples from wells 2-5 No. 2, 2-13 No. 2, and 2-11 No. 3, respectively. Orthophosphate ions were found in 3, 0, and 1 sections of the core samples from wells 2-5 No. 2, 2-13 No. 2, and 2-11 No 3, respectively. It should be pointed out that phosphate can react with constituents (*e.g.* calcium ions) in the formation and, consequently, the data only reflect soluble orthophosphate. The results, however, clearly demonstrated that the nutrients were being widely distributed in the oil-bearing formation.

Using cultural methods, microorganisms were shown to be present in all sections of cores from all three newly drilled wells and, as may be expected, the numbers varied but, the larger numbers in some samples suggest that they had proliferated. Heterotrophs and oil-degrading microbes were present in all samples as were both aerobes and anaerobes.

Samples from each section were examined by electron microscopy and, as would be expected, many samples showed no microbial cells. Scattered microbial cells as illustrated in Figure 17 were observed in a number of samples from all three wells and in some cases (see Figures 18, 19, and 20) large clusters of cells were observed indicating that the added nutrients had had the desired effect of promoting microbial growth in the reservoir.

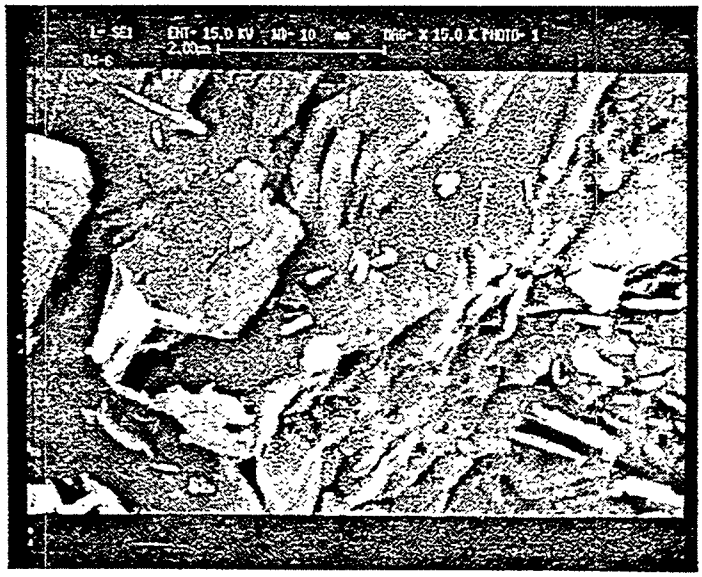


Figure 17. Electron micrograph of a sample of core from well 2-13 No.2, section 6. (Note the scattered microbial cells).

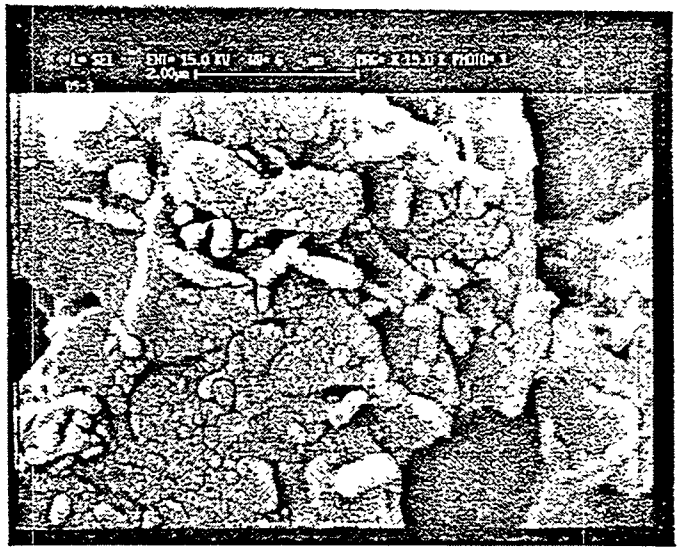


Figure 18. Electron micrograph of a sample of core from well 2-11 No.3, section 3. (Note the large number of microbial cells).

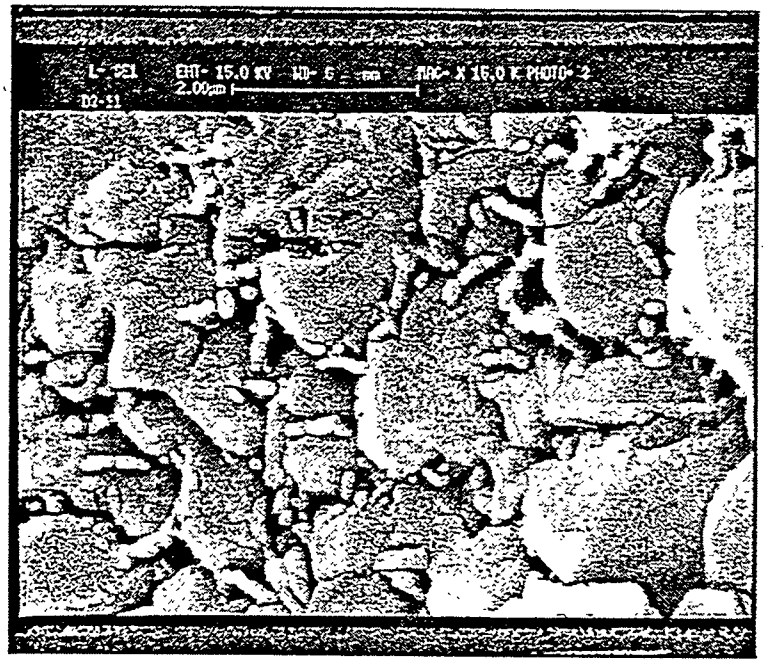


Figure 19. Electron micrograph of a sample of core from well 2-5 No.2, section 11. (Note the large number of microbial cells).

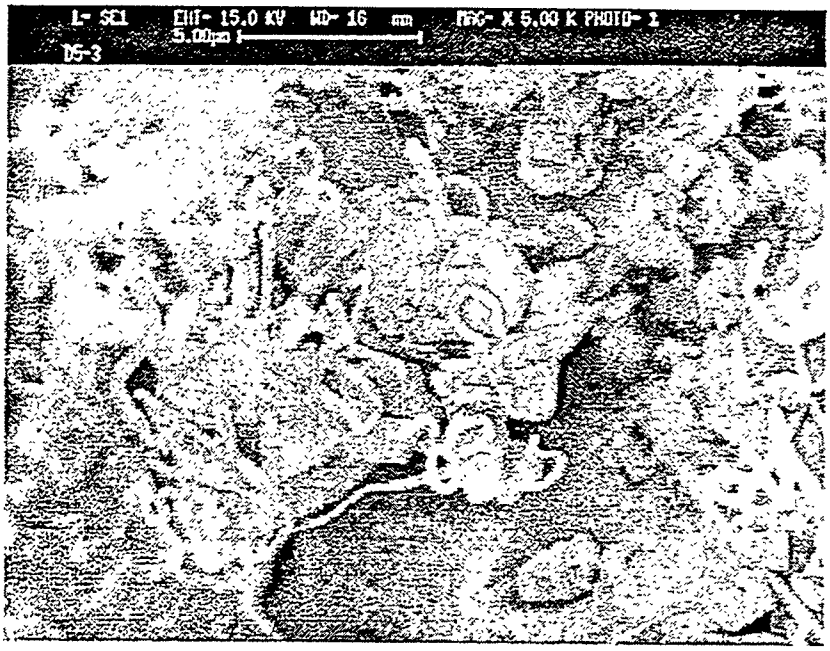


Figure 20. Electron micrograph of a sample of core from well 2-11 No.3, section 3. (Note the large number of microbial cells).

The core samples appeared to be massive, fine-grained, moderately mature, quartzarenite (a sandstone, Folk's classification) with abundant quartz, minor amount of feldspar, perhaps kaolinite, with minor calcitic cement component, probably ferroan dolomite.

The petrophysical properties of collected cores from the three newly drilled wells are given in Table 6. In this Table, the lowest, the highest, and a median range of values are presented to show the heterogeneity of the reservoir formation.

Table 6.
Petrophysical properties of cores from three newly drilled wells.

Well Name	Depth		Porosity (%)	Permeability (md)	Fluid Saturation		Grain Density (g/cc)
	m	ft			%Oil	%H_2O	
2-5 No. 2	670.94	2200	4.3	0.70	31.7	28.1	2.74
2-5 No. 2	679.52	2207	12.9	11.60	11.6	23.3	2.62
2-5 No. 2	675.51	2215	12.9	38.00	8.0	18.7	2.68
2-13 No. 2	666.36	2185	13.9	141.00	9.8	24.3	2.59
2-13 No. 2	670.33	2198	9.9	34.00	7.7	22.3	2.62
2-13 No. 2	673.38	2208	3.9	1.60	9.4	23.1	2.66
2-11 No. 3	663.92	2177	12.1	13.29	2.4	14.5	2.64
2-11 No. 3	668.50	2192	13.9	61.02	13.8	26.0	2.59
2-11 No. 3	669.72	2196	11.0	1.35	15.9	21.3	2.60

F. Expansion of Injection Program

During July 1997, an additional nutrient injection skid was completed and installed at Test Station 4. Piping modifications were made to allow six more injection wells to accept nutrient. The NBCU 3-16 No. 1, 2-12 No. 1, 2-10 No. 2, 34-7 No. 1, and 2-4 No. 1 wells all began nutrient injection during July, 1997. The total number of nutrient injectors for the last year of the project was ten as is shown in Figure 16. The nutrient additions to the ten injectors are given in Table 7.

G. Monitoring Program

Fluids from both injector wells and producer wells in all patterns were collected monthly as described previously.

Table 7.
Feed and feeding regime for all ten injector wells from July 1997-June 1998.

WELL NO.	MON.	TUES.	WED.	THURS.	FRI.
34-16 No. 1		0.16 N 0.04 P	-	0.28 M	-
2-4 No.1	0.10 N 0.03 P	-	0.20 M	-	-
2-6 No. 1	0.05 N	-	0.30 M	-	0.02P
34-9 No. 2	0.11 N	-	0.18 M	-	0.05 P
3-16 No.1	-	0.19 N 0.05 P	-	0.32 M	-
34-7 No. 1	-	0.17 N 0.04 P	-	0.21 M	-
2-10 No.2	-	0.12 N 0.02 P	-	0.19 M	-
11-5 No. 1	0.15 N	-	0.29 M	-	0.04P
2-12 No. 1	-	0.26 N 0.07 P	-	0.43 M	-
2-14 No. 1	0.08 N	-	0.47M	-	0.02 P

N = percent potassium nitrate (w/v),
P = percent sodium dihydrogen phosphate (w/v),
M = percent molasses (v/v).

1. Petrophysical Analyses

One of the main concerns in the application of MEOR is the integrity of original oil in place since the selling price of produced oil is directly based on its petrophysical properties. To confirm the integrity of produced oil, the following tests were conducted on produced fluids from selected wells in test and control patterns:

- API gravity (at room temperature). It is expected that API gravity of produced oil from Test Patterns will either stay steady or show an upward trend due to infusion of new oil from previously unswept area of the reservoir. The upward trend may continue to the level of the gravity of the original oil in place.

- Absolute viscosity, (at reservoir temperature). It is expected that the viscosity of produced oil from test pattern wells will exhibit either a steady or downward trend

due to the infusion of new oil from previously unswept areas of the reservoir. The downward trend may continue down to the lower viscosity of the original oil in place.

- Water-oil interfacial tension, IFT. It is expected that the produced fluid may exhibit a steady or downward trend in water-oil interfacial tension due to microbial production of surfactants.

- Water-air surface tension, ST, and pH. To insure nothing out of the ordinary may happen that causes degradation of the produced fluid, these properties of produced water were measured regularly.

Based on the above considerations, no deleterious changes in the characteristics of the produced oil were observed. Table A1 in the Appendix gives representative values for petrophysical characteristics of the produced fluids from selected wells in all patterns.

2. Microbiological Analyses

The microbiological analyses of production fluids did not show any significant changes attributable to the MEOR process. It should be pointed out however, that microorganisms prefer to grow attached to a substrate rather than be suspended in a medium. Consequently, numbers of microbes in production fluid do not necessarily reflect the size of the population in the reservoir.

3. Inorganic Ion Analyses

Production fluids were monitored for chloride ions, hardness, nitrate ions, phosphate ions, potassium ions, sulfate ions, and sulfide ions for the duration of the field demonstration.

No sulfide ions were detected in the fluids from any of the production wells (limit of detection 0.02 ppm) after six months of nutrient injection, but were present initially. This reduction in hydrogen sulfide was statistically significant. No significant changes attributable to the MEOR process were seen in the concentrations of chloride ions, hardness, potassium ions, or sulfate ions.

No nitrate ions were found in the produced fluids from any of the wells, although nitrate ions were found in some samples from all three of the newly drilled wells.

Phosphate ions were found in the produced fluids from producer wells in three of the four test patterns indicating that there was communication between the respective injector wells and those producer wells. The lack of the nitrate ions in samples indicates that they were either being consumed by the microflora or were reacting with materials in the reservoir since the presence of phosphate in samples demonstrates that there was communication between most injectors and some producer wells.

H. Results

1. Oil Production

The microbial permeability profile modification technology (MPPM) demonstrated in this project has resulted in, and continues to result in, the recovery of additional oil (hereinafter referred to as incremental oil recovery). The amount of incremental oil recovered from a well is the amount of oil that is recovered over and above that expected based on the decline curve of production from that well. It is interesting to note that with the passage of time, the incremental oil comprises an increasing percentage of the produced oil. Further, as will be pointed out later, incremental oil will continue to be produced long after the injection of nutrients has ceased.

In the present demonstration, the tracer study indicated that it would probably be at least seven months before evidence of microbial activity in the reservoir would become evident and indeed this proved to be the case. In fact, well 2-13 No. 1, that was shown to have good communication with test injector 2-14 No. 1, began to show enhanced production after seven months with a concurrent reduction in the rate of increase in the water-oil ratio (WOR). None of the other production wells in the program had veered from their natural decline curves at that time.

By the end of 1996 a total of eight of the fifteen production wells in test patterns showed a positive response to the nutrient injections (See Table 8). Conversely, two of the production wells in control patterns were abandoned due to an uneconomical production rate and five other wells continued their natural decline in oil production. The remaining producing well in the control patterns experienced increased oil production due to increased water injection into the nearby control injection well.

Thirty months after the first test injector well began receiving nutrients, there were no changes in the responses of the producing wells in the control patterns and one of the producing wells in a test pattern (well no. 2-3 No. 1) failed to continue its positive response and was therefore characterized as exhibiting a questionable response indicating that more time was needed to accurately evaluate the performance of this well. On the positive side of the ledger, three other producing wells in the test patterns showed evidence of responding positively to the nutrient injection and were classified as questionable at that time. These results clearly demonstrated that the nutrient injections were having a positive effect on oil production and it was requested (and approved by DOE) to expand nutrient injection by injecting nutrients into two control injectors [well 2-4 No. 1 (control pattern 1) and 34-7 No. 1 (control pattern 2)] and into four injector wells not previously included in the program (NBCU 34-16 No. 1, NBCU 2-12 No. 1, NBCU 2-10 No. 2, and NBCU 3-16 No. 1). Locations of the new injector wells are shown in Figure 16. Production data for all of the wells involved in the project with the exception of the two abandoned wells are given in Figures A1–A21 of the Appendix..

Twelve months after nutrient injection had been expanded to include 10 injectors, thirteen of nineteen producing wells had responded positively and two other wells yielded results

suggesting that they were beginning to respond positively. Only two of the producing wells in the original control patterns remained outside of the influence of the ten injectors receiving nutrients. Well 3-3 No. 1 continued on its natural decline while Well 3-1 No. 2 continued to exhibit increased oil production due to increased water injection in injector well 3-2 No. 1.

Table 8.
Oil production response from all wells included in the project.

Well No.	Pattern(s)	Response Evaluation Dec. 1996	June 1997	June 1998
2-11 No. 1	TP1, TP4	Positive	Positive	Positive
2-15 No. 1	TP1	None	Questionable	Questionable
11-3 No. 1	TP1, TP3	None	Questionable	Positive
2-13 No. 1	TP1, TP3	Positive	Positive	Positive
34-7 No. 2	TP2, CP2	None	Positive	Positive
34-16 No. 2	TP2	Positive	None	Questionable
34-15 No. 1	TP2, CP3	Positive	Positive	Positive
34-15 No. 2	TP2, CP3	Positive	Positive	Positive
34-10 No. 1	TP2, CP2	None	Questionable	Positive
10-8 No. 1	TP3	None	None	Positive
11-6 No. 1	TP3	Positive	Positive	Positive
11-4 No. 1	TP3	None	None	None
2-11 No. 2	TP4	Positive	Positive	Positive
2-3 No. 1	TP4, CP1	Positive	Questionable	Positive
2-5 No. 1	TP4, CP1, CP4	None	None	None
35-13 No. 1	CP1	Nat. Decline	Nat. Decline	Nat. Decline
35-14 No. 1	CP1	Shut-in	--	--
3-1 No. 1	CP1, CP3, CP4	Nat. Decline	Nat. Decline	Nat. Decline
34-2 No.1	CP2	Nat. Decline	Nat. Decline	Positive
34-6 No.1	CP2	Shut-in	--	--
3-3 No. 1	CP3	Nat. Decline	Nat. Decline	Nat. Decline
3-1 No. 2	CP3, CP4	*	*	*
3-9 No. 1	CP4	Nat. Decline	Nat. Decline	Positive

*Oil production increased due to an increase in the volume of injection water in control injector well 3-2 No. 1.

It is known that certain activities in the reservoir, such as the drilling of a new well, shutting-in a well, increasing the water injection rate in an injector well, etc., can alter the performance of other wells in the field. Indeed this was the case with well 2-11 No. 1, for when well 2-11 No. 3 was drilled and began producing, there was a steady drop in production from well 2-11 No. 1. However, when well 2-11 No. 3 was shut-in, production in well 2-11 No. 1

recovered. Also, as noted in Table 8, when the water injection rate in injector 3-2 No. 1 was increased, production from well 3-1 No. 2 increased.

There were, however, two wells that exhibited anomalous behavior. The first new well (well 34-6 No. 3) drilled during this project initially did not produce very well, but after fracturing, production increased appreciably. The interesting thing about this well is that production continued to increase slowly to over 16 m^3 (103 barrels per day) which is not characteristic of well performance in this reservoir. This unusual behavior could be a result of shutting-in well 34-6 No. 1, accessing a new oil pool, or a result of nutrient injection into injector well 34-7 No. 1.

In the second case, the fluid production from well 3-1 No. 1 also is unusual in that oil production remained essentially steady from July 1997 thru July 1998, while water production dropped drastically. The most logical explanation for this situation is that microbial growth had restricted water channels from injector wells 2-4 No. 1 and 34-16 No. 1. However, without other information this well was not characterized in Table 8 as yielding a positive response to the nutrient injections.

2. Evidence of New Oil in Produced Fluids.

Gas chromatographic profiles of the oil from all of the producing wells involved in this study were evaluated to determine if "new oil" (*i.e.* oil previously bypassed by the waterflood) was present in the produced fluid from the reservoir. Since the lighter hydrocarbons are produced earlier in the life of a reservoir and more of the water-soluble compounds are produced before the heavier less water soluble ones, their concentration in the oil fraction decreases as the reservoir ages.

Conversely, "new oil" contains a greater concentration of these lighter fractions of the oil. GC data collections began in 1995 and continued throughout the field demonstration. It is realized that quantitative comparisons for given compounds would not be fruitful because the multiplicity of steps involved in obtaining and preparing samples for analysis precluded having the exact same amount of oil for each analysis. On the other hand, the ratio of components in the samples should be more or less constant irrespective of the amount of sample analyzed. Therefore, the ratio of the lighter components in the oil to the heavier components should increase if "new oil" is present in the sample. Rather than make comparisons between single compounds, the area under the curve on the chromatograms was divided into four groups and comparisons made between the area under the curve on the chromatogram for the four groups. Group 1 compounds consist of the area under the curve from n-hexane (C_6) up to n-dodecane (C_{12}). Group 2 compounds consist of the area under the curve from n-dodecane (C_{12}) up to n-octadecane (C_{18}). Group 3 compounds consist of the area under the curve from n-octadecane (C_{18}) up to n-tetracosane (C_{24}). Group 4 compounds consist of the area under the curve from n-tetracosane (C_{24}) up n-triacotane (C_{30}).

When comparing the changes in ratio of different groups with time, it became apparent that there were very few changes in the ratios of the Group1 compounds to Group 2 compounds, Group 2 compounds to Group 3 compounds, or the Group 3 compounds to the Group 4 compounds. On the other hand, an increase in the ratio of Group 1 compounds to Group 4 compounds demonstrated the presence of "new oil" in the produced fluid from a given well. It was interesting to note that the changes in the ratio of Group 2 compounds to the Group 4 compounds parallel those of the ratio of the Group 1 compounds to the Group 4 compounds. Bar graphs showing the ratios between the different groups of hydrocarbons for each well are shown in Figures A1-A21 in the Appendix. The same data for the two wells drilled in 1994 are shown to illustrate the normal change in ratios with time (see Figures A22-A23 in the Appendix).

The data given in the Appendix show that of the 13 wells characterized as having given a positive response in terms of oil production, nine were confirmed as positive (new oil) by the ratio of Group 1 compounds to Group 4 compounds. One may have contained a small amount of new oil, and three did not show evidence of "new oil".

Of the two wells characterized as being questionably positive from an oil production standpoint, one (34-16 No. 2) showed evidence of "new oil" while the other well (2-15 No. 1) did not.

Of the five wells characterized as not showing positive or questionable response in terms of enhanced oil production, one well gave no indication of "new oil" but four showed the presence of some "new oil" even though they did not exhibit a positive response from an oil production standpoint. Thus, it appears that some new oil was finding its way into the produced fluids of these two wells even though it did not manifest itself sufficiently to be considered a positive response. Production from the three new wells drilled in 1996 distorted production figures from one well (2-5 No. 1) to such an extent that no meaningful assessment could be made.

3. Analysis of Produced Gas

Another piece of evidence pointing to the infusion of "new oil" into the produced fluids was obtained from gas analyses performed on samples from a number of wells. Increased gas production that had been noted in some wells could have been the result of microbial activity or it could have come from previously unswept areas of the reservoir. Samples of gas were collected from selected production wells and analyzed by GC using a Fisher Gas Partitioner Model 1200 (dual column, dual detector chromatograph). Only a limited number of samples were analyzed but there was no evidence of changes in the composition of the produced gases due to microbial gas production, (*i.e.* no carbon dioxide or hydrogen was observed). The data suggest that the increase in gas production was due to gases from previously unswept areas of the reservoir since they contained a percentage of propane more closely like that of gas obtained from the field in earlier years.

4. Distribution of Nutrients Throughout the Reservoir

Indications are that nutrients are being distributed throughout the reservoir. It should be pointed out that phosphate ions were found in the produced fluids from producer wells in three of the four test patterns (1, 2, and 3) demonstrating that there was communication between the respective injector wells and the surrounding producer wells. The lack of the nitrate ions in samples indicates that it was either being consumed by the microflora or was reacting with materials in the reservoir since the presence of phosphate in samples demonstrates that there was communication between most injectors and some producer wells.

Fluid from cores from the three wells drilled nearly two years after nutrient injection began (Fall, 1996) were examined for the presence of nitrate ions and orthophosphate ions in five sections of core from each well. Nitrate ions were present in 4, 3, and 5 sections of core samples from wells 2-5 No. 2, 2-13 No. 2, and 2-11 No. 3, respectively. Orthophosphate ions were found in 3, 0, and 1 sections of the core samples from wells 2-5 No. 2, 2-13 No. 2, and 2-11 No. 3, respectively. These results clearly demonstrate that the nutrients were being widely distributed in the oil-bearing formation.

5. Evidence of Microbial Proliferation in Reservoir

Investigations into changes in the microbial population of the reservoir on the basis of their presence in produced fluids was of limited value in view of the fact that the wells did not contain packers. As a result, the microbial content of the produced fluids could be influenced by the microbial content of the fluid in the casing. Furthermore, since most microorganisms prefer to grow attached to the strata rather than free-floating in fluid, analysis of produced fluid may not reflect the true population in the reservoir. On the other hand, analyses performed on cores taken from the reservoir did yield valuable information. Cores from the second well drilled in 1994, in an area of the reservoir not being swept by the waterflood, were found to contain isolated microbial cells but no evidence of proliferation. The fact that sulfate-reducing bacteria (SRB) were present in the drilling fluid, but not in the core samples analyzed, was strong evidence that the microflora found in the core was indigenous to the reservoir, not contaminates from the drilling fluid.

Core samples from the three wells drilled in the Fall of 1996 were examined for the presence of microorganisms by cultural methods. All five sections of core from each of the three wells contained viable microorganisms. While some samples contained only a few microorganisms, most contained considerably more than the core samples taken from the earlier well (34-3 No. 2) drilled in 1994 as shown in Tables 2 and 9. Samples from each section also were examined by electron microscopy and, as would be expected, many samples showed no microbial cells. Scattered microbial cells as illustrated in Figures 17 were observed in a number of samples from all three wells and in some cases large clusters of cells were observed indicating

Table 9
Numbers of microorganisms in sections of cores from three newly drilled wells.

Well No.	Core Section (No.)	Depth m	Depth ft	Heterotrophs Aerobic (No./g)	Heterotrophs Anaerobic (No./g)	Oil-Degrading Aerobic (No./g)	Oil-Degrading Anaerobic (No./g)
2-5 No. 2	3	676.12	2217	3	*	0	*
2-5 No. 2	5	675.21	2214	29	*	3	*
2-5 No. 2	11	673.38	2208	7	*	11	*
2-5 No. 2	12	672.46	2205	138	*	250	*
2-5 No. 2	15	669.41	2195	>300	*	>300	*
2-13 No. 2	4	671.85	2203	250	4	175	<1
2-13 No. 2	6	670.94	2200	>300	14	103	<1
2-13 No. 2	11	670.02	2197	>300	11	>300	1
2-13 No. 2	13	667.89	2190	>300	41	125	<1
2-13 No. 2	15	666.06	2184	>300	20	105	1
2-11 No. 3	3	670.33	2198	231	30	182	48
2-11 No. 3	7	667.28	2188	250	71	163	50
2-11 No. 3	8	666.67	2186	179	59	102	38
2-11 No. 3	10	665.45	2182	>300	85	145	62
2-11 No. 3	14	663.92	2177	>300	52	153	33

*insufficient sample

that the added nutrients had the desired effect of promoting microbial growth in the reservoir (see Figure 18, 19, and 20).

Still one other piece of data supporting the widespread distribution of nutrients (nitrate) and/or the growth of microorganisms (nitrate-reducing bacteria) in the reservoir was the statistically significant reduction in sulfide content of fluids from the field six months after nutrient injection began. Both nitrate per se and the growth of nitrate-reducing microorganisms have been shown to inhibit SRB's and their production of sulfide from sulfate[13].

6. Performance of Nutrient Injector Wells

Performance of injection well 2-14 No. 1 (Test Pattern 1)

The injection volume declined despite an increase in injection pressure. This performance may be an indication of permeability reduction due to microbial growth near the wellbore (see Figure A24).

Performance of injection well 34-9 No. 2 (Test Pattern 2)

Injection pressure increased and injection volume decreased. This performance may be an indication of permeability reduction due to microbial growth near the wellbore (see Figure A25).

Performance of injection well 11-5 No. 1 (Test Pattern 3)

The injection volume declined and there was a slight increase in injection pressure which may be an indication of permeability reduction due to microbial growth near the wellbore (see Figure A26).

Performance of injection well 2-6 No. 1 (Test Pattern 4)

This well's injection rate and pressure were very sensitive to production (or lack of) from well 2-11 No. 3. Injection pressure increased and the injection volume decreased over the last year (see Figure A27).

Performance of injection well 2-4 No. 1 (was injector for Control Pattern 1)

Injection volume declined as injection pressure increased (see Figure A28).

Performance of injection well 34-7 No. 1 (was injector for Control Pattern 2)

Injection volume declined as injection pressure increased (see Figure A29).

Performance of injection wells 34-16 No. 1 (not in original program)

Injection pressure increased and there was more water intake. There was no indication of plugging (see figure A30).

Performance of injection well 2-12 No. 1 (not in original program)

Injection pressure increased and there was more water intake. There was no indication of plugging (see Figure A31).

Performance of injection well 3-16 No. 1 (not in original program)

Injection pressure increased and there was more water intake. There was no indication of plugging (see Figure A32).

Performance of injection well 2-10 No. 2 (not in original program)

Injection pressure increased and there was more water intake. There was no indication of plugging (see Figure A33).

7. Overall Performance of Field Demonstration

In evaluating the overall performance of the MPPM treatment in the field, it must be remembered that only four of the twenty injector wells in the field received microbial nutrients before July 1997. Oil production for the field from Jan. 1992 through Aug. 1998 is given in Figure 21. The performance of each producing well in both control and test patterns and including the two wells drilled in 1994 is shown graphically in Appendix A1-A23. During the period May 1994 through Dec. 1998, total oil production was 74,700 m^3 (470 MBO). Based

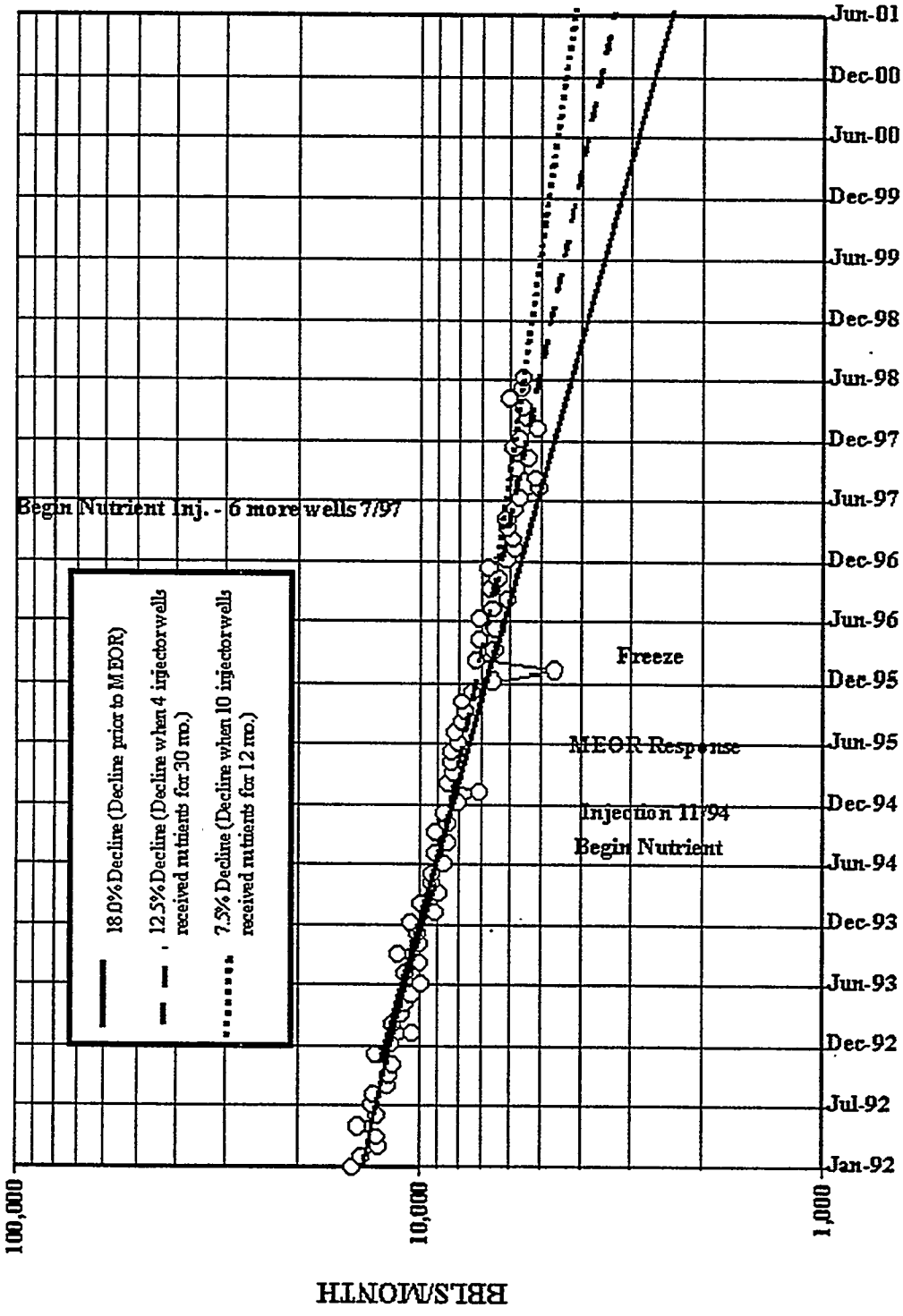


Figure 21. Total production from North Blowhorn Creek Unit excluding newly drilled wells.

on projections derived from the period of Jan. 1992-Apr. 1994, oil production from May 1994-Dec. 1998 should have been only 49,175 m^3 (309 MBO). Of this 25,000 m^3 (161 MBO) of incremental oil produced, 14,563 m^3 (92 MBO) were production from the five new wells, leaving a total of 11,000 m^3 (69 MBO) of oil attributable to the MEOR treatment.

Further, calculations based on production from Jan. 1992 through Apr. 1994 indicate that the field would reach its economic limit of 238 m^3 (1500 bbls) of oil per month on Jan. 1, 2003. Based on the current oil production rate, the expected economic life of the field has been extended by 60-137 mo. exclusive of any additional positive response from continued nutrient injection into the ten test injector wells. The expected total project incremental oil recovery is projected to be 63,600-95,400 m^3 (400-600 MBO).

V. DISCUSSION

When the primary production phase of an oil field approaches its economic limits, waterflooding is often the most promising and economical method of increasing oil recovery. Today over 50% of all the oil fields in the world are under waterflooding operations. As the waterflooding continues, fluid flow in the reservoir normally seeks larger channels, leaving smaller channels untouched. In time, water will sweep out all of the oil that was in its pathway, and a time will come when there will be no more oil for water to sweep out. Subsequently, water will be circulated in and out of the reservoir without sufficient oil recovery to sustain the operation (watered-out wells), resulting in a substantial volume of the original oil in place being left unrecovered.

The objective of this project was to use indigenous microbial biomass, generated by certain feed and feeding regimes in watered-out channels, to circumscribe the reservoir pore channels (microbial permeability profile modification, MPPM). Thus, injected water will be forced to alter its pathway and flow into unswept channels and sweep oil from them. The process of restricting watered-out channels and invading new and unswept oil-bearing channels will continue so long as the condition of a controlled growth and proliferation of *in situ* microbes prevails and other unforeseen reservoir characteristics or production activities do not create unpredicted obstacles.

The MPPM technology demonstrated in this project differs from most MEOR methods in a number of ways. For example, one of the distinctive features of the present technology is that it relies on the activities of the *in situ* microflora rather than on cultures that are injected into the reservoir. Early reports on the presence of microorganisms in petroleum reservoirs were viewed with extreme skepticism due to questionable sampling techniques[14]. More recently, however, it has been established beyond doubt that microorganisms are indigenous to oil reservoirs, not merely residents that have been introduced through drilling activities[14]. In fact, a previous DOE-sponsored project reported on the microbial population in cores from areas of 13 reservoirs uncontaminated by previous EOR activities[12]. In this earlier DOE-sponsored project[7] it was shown that these native microbial populations did respond to the introduction of simple inorganic nutrients (*e.g.* sodium nitrate and dipotassium hydrogen phosphate). Not only did the microorganisms reproduce but they also elaborated an array of byproducts that assisted the oil recovery endeavors. The advantage of relying on the *in situ* microbial population in the reservoir is that the microorganisms are already distributed throughout the reservoir and those in areas influenced by waterflooding will be supplied with nutrients that are required for growth. Furthermore, as new areas of the reservoir receive injection water, the microbial population already in place will be able to take advantage of the added nutrients. In the case of processes requiring the injection of microbial cultures, considering the slowness with which injection water travels in a reservoir (with the exception of fractures) coupled with the filtering effect of the oil-bearing strata itself, distribution of injected microorganisms to any appreciable extent has to be extremely limited.

To help understand how the present technology modifies the waterflood profile, the following explanation is offered. An average microbial cell is about one micron in length by 0.5 microns in diameter and most grow attached to a substrate rather than floating free in the water. Bacteria reproduce by a process known as binary fission which means one bacterial cell divides into two cells, they in turn divide into two more cells each and so on. Given the nutrients required for growth, the bacterial cells attached to the walls of water channels in the reservoir will begin to reproduce, thus reducing the orifice of the channel.

The question arises as to the length of time required for a microorganism to divide. Obviously, this varies from species to species and the environmental conditions under which they are growing. While some species will divide every 20 minutes during logarithmic growth under ideal conditions, the doubling time for the bacteria in the reservoir is probably hours, if not days. Even so, their impact on the waterflood profile will be dramatic in a relatively short period of time.

Thus, even with a doubling time measured in days, a significant shift in injection water flow would occur in a very short period of time. The MPPM accomplished by the microbial growth is illustrated in Figure 22. It must be remembered that when injection water is diverted to unswept areas of the reservoir, the nutrients included therein will be available for the microbes in these areas and the process described above will be repeated. A quantitative comparison of this whole field MEOR technology to single well MEOR treatment is given in Figure 23. Thus, where applicable, whole field (or a portion thereof) treatment significantly increases the potential incremental oil that can be recovered. This points up another major difference between the MEOR technology of this project and that of other MEOR methods.

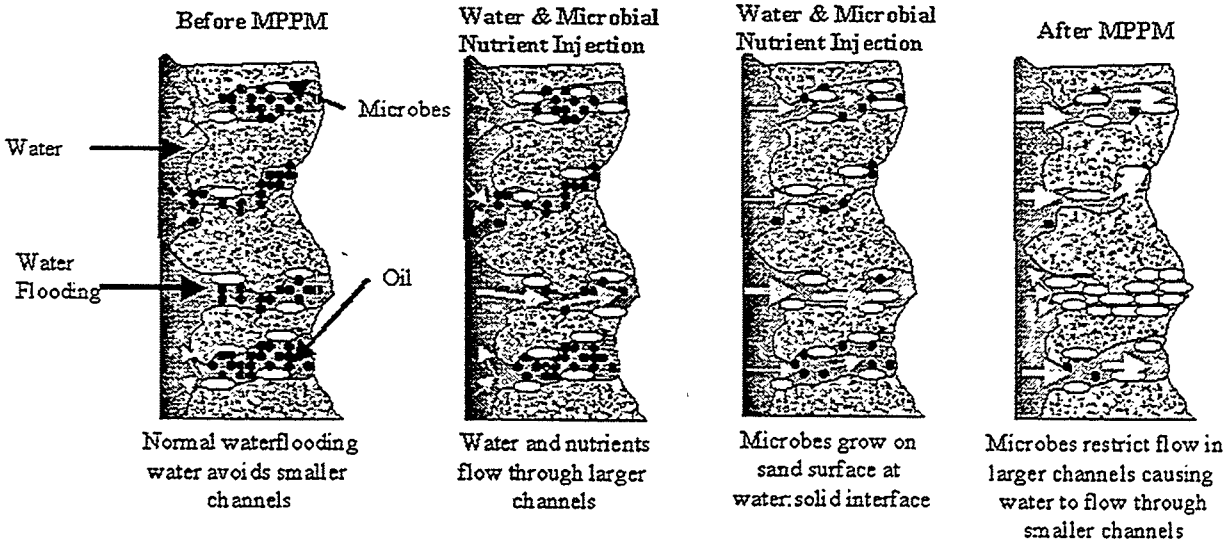


Figure 22. Mechanism of microbial enhanced oil recovery (MEOR) using *in situ* microbial permeability profile modification (MPPM) to enhance oil recovery.

Field Charcteristics of a Hypothetical Oil Reservoir:

Area:

MPPM[1] 161,880 m^2 (40 Acres)

Individual well MEOR[2] 2918.63 m^2

Pay zone thickness(h): 6.096 m (20 ft)

Porosity(φ): 18%

Oil saturation: 65%

Water: 35%

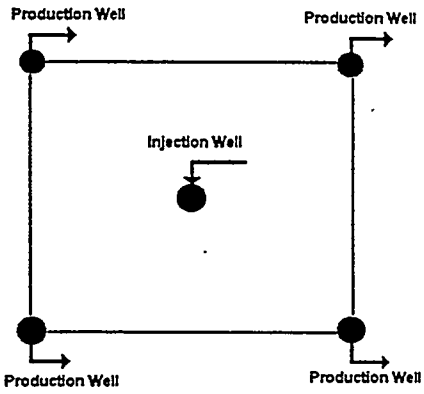
% Recovery:

MPPM 25%

Individual well MEOR 50%

1. Microbial Permeability Profile Modification EOR.

2. Injected microorganisms are assumed to have a 30.48 m (100 ft) (30.48 m) radius of travel in the pay zone.
Area = (30.48 m)^2 x π = 2918.63 m^2 (0.72 acre)



5-Spot Injection-Production Pattern

	MPPM		Individual well	
Bulk volume	986,785 m^3	34,848,000 ft^3	17,792 m^3	628,318 ft^3
Pore volume	177,621 m^3	6,272,640 ft^3	3,203 m^3	113,097 ft^3
Oil in place	115,343 m^3	725,483 barrels	2,080 m^3	13,080 barrels
Primary production	39,372 m^3	247,644 barrels	624 m^3	3,924 barrels
Remaining oil	80,740 m^3	507,838 barrels	1,456 m^3	9,156 barrels
Incremental Oil	20,185 m^3	126,959 barrels	727 m^3	4,572 barrels

The MPPM method produces 20,185 m^3 (126,959 barrels) of oil (using a 5-spot pattern with 4 producing wells) while the individual well MEOR also applied to 4 wells would yield 2,907 m^3 (18,287 barrels).

MPPM produces 694% more oil.

Figure 23. Comparison of MPPM EOR treatment (5-spot Pattern) vs. individual well MEOR treatment.

From an environmental perspective, the MPPM technology offers the advantage of not having to introduce microorganisms into the environment. This is especially important if genetically-engineered microbes are involved and where spills or eventual escape into the environment are possible. The nutrients employed in the MPPM are environmentally friendly, whereas in many MEOR processes the chemicals employed are proprietary and their environmental impact cannot be addressed herein.

Perhaps, one of the most important features of the MPPM is its relatively low cost per barrel of incremental oil. It is important to note that this technology does not interfere with normal waterflooding operations. In fact, all that is required is to add a facility to dissolve the chemical nutrients and feed them into the injection water stream. The number of such facilities required will, of course, depend upon the individual oil field. Similarly, the design can be simple to slightly more complex. The nutrients themselves are relatively inexpensive. For example, for the present project potassium nitrate cost $35/45.4 kg (100 lbs), sodium dihydrogen phosphate cost $100/45.4 kg (100 lbs), and molasses cost $67/387.5 liters (100 gal). On a weekly basis and assuming an injection rate of 521 m^3 (3275 bbl) of water/day, chemical costs would only be $1,400/ wk using the average schedule employed for the final 12 months of the project. Labor costs, of course, would vary but in the present project amounted to an average of 20 man-hours per week.

Finally, it should be emphasized that the MPPM technology can be employed in many fields where waterflooding is possible, irrespective of the geological formation involved.

VI. TECHNOLOGY TRANSFER

The last year of this project was devoted to analyzing data and to technology transfer. It is realized of course, that technology transfer is an on-going process and to date, the following papers have been published.

Brown L.R., A.A. Vadie, J.O. Stephens, and A. Azadpour, 1996. Enhancement of the Sweep Efficiency of Waterflooding Operations by the In-Situ Microbial Population of Petroleum Reservoirs. Proceedings of the Fifth International Conference on Microbial Enhanced Oil Recovery and Related Biotechnology for Solving Environmental Problems, pp. 95-114, Dallas, TX.

Vadie, A.A., J.O. Stephens, and L.R. Brown, 1996. Utilization of Indigenous Microflora in Permeability Profile Modification of Oil Bearing Formations. Proceedings 1996 SPE/DOE Tenth Symposium on Improved Oil Recovery, pp 459-471, Tulsa, OK.

Azadpour, A., L.R. Brown, and A.A. Vadie. 1996. Examination of Thirteen Petroliferous Formations for Hydrocarbon-Utilizing, Sulfate-Reducing Microorganisms. Journal of Ind. Micro. 16, 263-266.

Brown, L.R., A.A. Vadie, and J.O. Stephens, 1997. Field Demonstration of the Ability of *in situ* Microorganisms in Oil-Bearing Formations to Modify Waterflooding Profiles. Proceedings of the 1997 Eastern Section AAPG and TSOP Joint Meeting, pg 24-26.

Brown, L.R., A.A. Vadie, and J.O. Stephens, 1998. Going underground to spy on MEOR microbes and finding many MEOR barrels of incremental oil. The Class Act, DOE's Reservoir Class Program Newsletter. Vol. 411, Winter 1998.

A review of the project was published in "LORE" in Nov. 1998. [LORE is a publication of the Water Resources Research Institute of Mississippi.]

Prepared an update on the results of the project for Dr. Herb Tiederman of DOE for testimony for Congress.

In addition to presentations made at the Annual Contractors Review Sessions with DOE, the following presentations have been made.

Brown, L.R., A.A. Azadpour, and A. Vadie. 1996. Microbial Activity in Petroleum Reservoir Formations. Presented at the Society for Industrial Microbiology Meeting held in the Research Triangle, N.C. in Aug. 1996.

Brown, L.R., A.A. Vadie, J.O. Stephens, and A. Azadpour, 1996. Enhancement of the Sweep Efficiency of Waterflooding Operations by the In-Situ Microbial Population of Petroleum Reservoirs. Presented at the Fifth International Conference on Microbial

Enhanced Oil Recovery and Related Biotechnology for Solving Environmental Problems, Dallas, June 1996.

Vadie, A.A., J.O. Stephens, and L.R. Brown, 1996. Utilization of Indigenous Microflora in Permeability Profile Modifications of Oil Bearing Formation. Presented at the 1996 SPE/DOE Tenth Symposium on Improved Oil Recovery. Tulsa, OK.

Brown, L. R. 1997 made a presentation to the 1997 Eastern Section AAPG and TSOP Joint Meeting on Sept. 30, 1997, in Lexington KY, entitled "Field Demonstration of the Ability of Microorganisms in Oil-Bearing Formations to Modify Waterflooding Profiles.

Brown, L.R., 1998 presented a seminar to the Biology Dept. of the University of Nevada at Las Vegas entitled "Using Microorganisms to Improve Oil Recovery" on March 13, 1998.

Brown, L.R. 1998 made a presentation to the Southern Great Lakes Local Section of the Society for Industrial Microbiology on Oct. 10, 1998 at Michigan State University. "Microbial Enhanced Oil Recovery".

Brown, L.R. and A.A. Vadie made a presentation on Microbial Enhanced Oil Recovery at the Society of Petroleum Engineers Los Angeles Basin Section in Long Beach, CA in Nov. 1998.

Stephens, J.O., L.R. Brown and A.A. Vadie 1998 made presentations at the Petroleum Technology Transfer Council Workshop held in Jackson, MS on Nov. 4, 1998, "Microbial Enhanced Oil Recovery": North Blowhorn Creek Unit, Black Warrior Basin, Northwest Alabama. This presentation was sponsored by the Petroleum Technology Transfer Council.

A presentation to the Permian Basin Chapter-Society of Petroleum Engineers Recovery Study Group, was carried out on February 11, 1999 in Midland TX. The presentation was made by J. O. Stephens and L. R. Brown.

A presentation was made to the Society of Petroleum Engineers meeting in Bartlesville, OK on Feb. 18,1999. The presentation was made by J. O. Stephens, L. R. Brown, and A. A. Vadie. Discussions also were held with personnel from Phillips Petroleum Co. relative to use of MEOR in one of their projects.

A presentation was made to the Society of Petroleum engineers on May 13, 1999 in Jackson, MS by James O. Stephens.

A PTTC workshop entitled "Microbial Options for Increasing Oil Recovery" was held in Midland, TX on June 3, 1999. James O. Stephens, Lewis R. Brown, and A. Alex Vadie participated in the workshop.

A PTTC workshop entitled "Microbial Options for Increasing Oil Recovery" was held in Zanesville, OH on June 21, 1999. James O. Stephens, Lewis R. Brown, and A. Alex Vadie participated in the workshop.

A presentation entitled "A Low Cost Solution for Enhanced Waterflood Performance" was presented to the 1999 Oil and Gas Conference held in Dallas, TX, June 28-30, 1999.

Letters were sent to PTTC regional directors offering our services for a workshop on the project. Additionally, similar letters were sent to a large number of oil companies making the same offer.

There also were a number of cases where we have engaged in technology transfer on a more or less one-on-one basis. For example, L.R. Brown and A.A. Vadie had several hours of discussion with a group from Tidelands Oil Co. in Long Beach, CA. Also, material on our findings was sent to personnel at Chevron Pet. Tech. Co. as a result of the presentation.

A number of individuals throughout the country have inquired by phone and e-mail and appropriate responses have been made.

The three principal investigators on this project were indeed honored by the fact that this project was selected as the **Best Advanced Recovery Project** for the Gulf Coast area by *"Harts Oil and Gas World"*. This award was made even more meaningful by the fact that it was nominated by the National Petroleum Technology Office and that each principal investigator received a letter of congratulations from the Secretary of Energy, Bill Richardson.

VII. SUMMARY & CONCLUSIONS

The North Blowhorn Creek Unit (NBCU) oil field was discovered in 1979 with some 2.54 x 10^6 m^3 (16 MM bbls) of IOIP and was unitized in 1983. Following its primary oil production phase, waterflooding started in 1983. The economic life of the oil field was expected to terminate in 2003 with over 1.59 x 10^6 m^3 (10 MM bbls) of IOIP left unrecovered. This fluvial dominated deltaic reservoir was employed in a "Class I Oil Program - Mid Term Activities", project that demonstrated the effectiveness of a microbial permeability profile modification (MPPM) technology for enhancing oil recovery and extending the projected economic life of the field by 60-137 months. Initially the field program involved injecting microbial nutrients into four test injector wells and monitoring the performance of the surrounding producer wells. The performance of these test producer wells were compared to the performance of control producer wells surrounding four other injectors that did not receive nutrients. Thus, the performance of each test producer well was compared to the performance of similar wells in the same formation as well as to its own historical record. Chemical, microbiological, and petrophysical analyses were performed on fluids from all wells on a monthly basis for the duration of the demonstration. The feeding regime was modified twice during the course of the project and, for the last 12 months, 10 injector wells received nutrients. The nutrients employed were potassium nitrate, sodium dihydrogen phosphate, and molasses. Initially the feeding regimes were formulated on the basis of core flood experiments performed using cores from a well drilled in an area of the reservoir that had not been influenced by the waterflood.

The wide distribution of the injected nutrients was confirmed by:

- The presence of orthophosphate ions in producing wells in three of the four original test patterns and
- the presence of nitrate ions and orthophosphate ions in core samples from three wells drilled within the oil field after nutrient injection for 22 months.

Involvement of microorganisms in enhancing oil recovery and proof of □new oil□ in the produced fluids as a result of microbial permeability profile modification was demonstrated by:

- The recovery of large numbers of viable microorganisms from cores of wells drilled within the field,
- electron micrographs showing large numbers of microbial cells in some of the cores cited above,
- analysis of the gas chromatographic profiles of produced oil illustrate the presence of □new oil□ (oil from unswept areas of the reservoir), and

- changing the composition of produced gases to be more like that produced originally.

The microbial permeability profile modification technology demonstrated in this project resulted in:

- The production of 10,970 m^3 (69,000 bbl) of incremental oil by the end of December 1998,
- projections for the recovery of a total of 64,000-95,000 m^3 (400,000-600,000 bbl) of incremental oil by the end of the economic life of the field, exclusive of production from the new wells drilled during the project, and
- extended the economic life of the field by 60-137 months.

The attractive features of the microbial permeability profile modification technology are:

- It does not interfere with normal waterflooding activities,
- may be used in any geological formation amenable to waterflooding,
- it is environmentally friendly since no microorganisms are added to the wells and only common plant fertilizers are employed,
- it enhances oil recovery and increases the economic life of the oil field, and
- it is the least expensive of all EOR processes in terms of cost per barrel of incremental oil recovered. [Based upon costs incurred in this project and the projected ultimate incremental recovery, the incremental cost per barrel of incremental oil is in the range of $1.10. to $1.65.]

VIII. ACKNOWLEDGEMENTS

The authors wish to express their sincere appreciation to the following individuals at Mississippi State University (MSU) for their contributions to the conduct of this project: to Todd and Scott French for their assistance in the preparation of reports and the conduct of laboratory experiments; to Michelle Badon and Robin Felder for their assistance in laboratory analyses; to Joanne Cotton for her secretarial assistance; to Jose Vasquez and John E. Parker for their efforts in the petroleum engineering phase of the project. A special thanks also goes to the late Dr. Ralph Powe, Vice President for Research at MSU, without whose help this project may never have come to fruition.

Special acknowledgements also should go to Angie Rushing for her tireless help in preparing all quarterly, yearly, and final reports and to field operators Thomas Keene, James Tate, William R. Brown, Paul Reynolds and the late Ronald Swindle for making the field end of the project work.

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APPENDIX

NOTE

Figures A1-A21 show fluid production and oil characteristics for each producing well involved in this study with the exception of wells 34-6 No. 1 and 35-14 No. 1 that were abandoned. The same information is given in Figures A22-A23 for the first two wells initially drilled during this project and illustrate changes in the ratio of compounds in the oil with time.

Group 1 compounds consist of the area under the curve from n-hexane (C_6) up to n-dodecane (C_{12}). Group 2 compounds consist of the area under the curve from n-dodecane (C_{12}) up to n-octadecane (C_{18}). Group 3 compounds consist of the area under the curve from n-octadecane up to n-tetracosane (C_{24}). Group 4 compounds consist of the area under the curve from n-tetracosane up to n-tricotane (C_{30}).

When comparing the changes in ratio of different groups with time, it became apparent that there were very few changes in ratio of the group 1 compounds to group 2 compounds, group 2 compounds to group 3 compounds, or the group 3 compounds to the group 4 compounds. As expected, the ratio of group 1 compounds to group 4 compounds (hereinafter referred to as 1:4) were the most significant and increases in this ratio with time indicate " new oil" in the produced fluid. Conversely, decreases in the 1:4 ratio indicate a weathering of the oil as the lighter, more soluble compounds are extracted by the water. It was interesting to note that the changes in the ratio of group 2 compounds to the group 4 compounds parallel those of the ratio of the group 1 compounds to the group 4 compounds.

Graphs showing pressure and rate of water injection for the ten injector wells that received nutrients are given in Figure A24-A33.

Table A1.
Petrophysical analyses of fluid from selected test and control wells.

PATTERN 1

Test Well 2-15 No. 1

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	28.93-35.2	2.14-1.82	53-65	29.6-23.6	7.75-7.5
Trend	upward	downward	steady	downward	steady

Test Well 2-13 No. 1

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	30-32	1.85-1.40	55.7-64.25	22.8-23.6	7-7.72
Trend	upward	downward	steady	steady	downward

Test Well 3-1 No. 1

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	30.40-33.25	2.43-1.7	59-65	28.4-26	7.5-8.15
Trend	steady	downward	upward	downward	steady

PATTERN 2

Test Well 34-7 No. 2

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	29.52-32.2	2.69-2.44	63-54	25.35-22.1	7.7-7.5
Trend	upward	steady	upward	steady	steady

Test Well 34-2 No. 1

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	31-33.7	1.74-1.95	58-68	23-25.25	7.7-7.5
Trend	upward	steady	upward	steady	steady

PATTERN 3

Test Well 10-8 No. 1

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	29.8-28	2.96-2.98	62.1-69.7	27.75-23.56	7.3-7.5
Trend	upward	upward	steady	steady	steady

Table A1. Continued

Test Well 11-4 No. 1

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	28.9-30.47	3.65-1.98	64.4-56.1	24.65-21.3	7.7-7.55
Trend	upward	downward	steady	downward	steady

Control Well 3-3 No. 1

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	34.11-30.8	2.32-2.45	61.9-57.6	26.9-22.7	7.75-7.25
Trend	steady	steady	steady	downward	steady

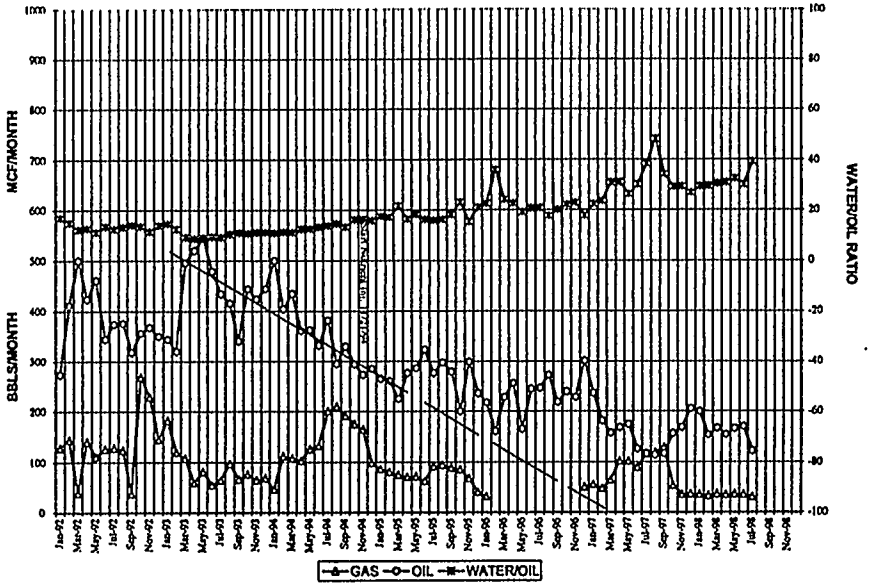
PATTERN 4

Test Well 2-11 No. 2

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	32-33	2.3-2.16	60-63	22.8-22	7.8-7.25
Trend	steady	downward	steady	downward	steady

Control Well 3-9 No. 1

	Gravity API	Viscosity cP	Surface Tension w-air, dyne/cm	Interfacial Tension o-w, dyne/cm	pH
Range	33-32	2.2-2	59-64	20-22	7.6-7.25
Trend	steady	downward	steady	steady	steady



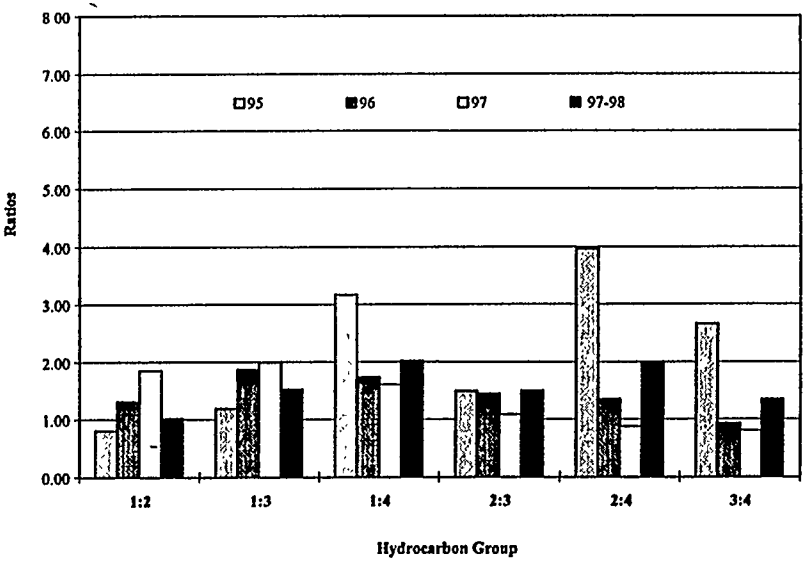
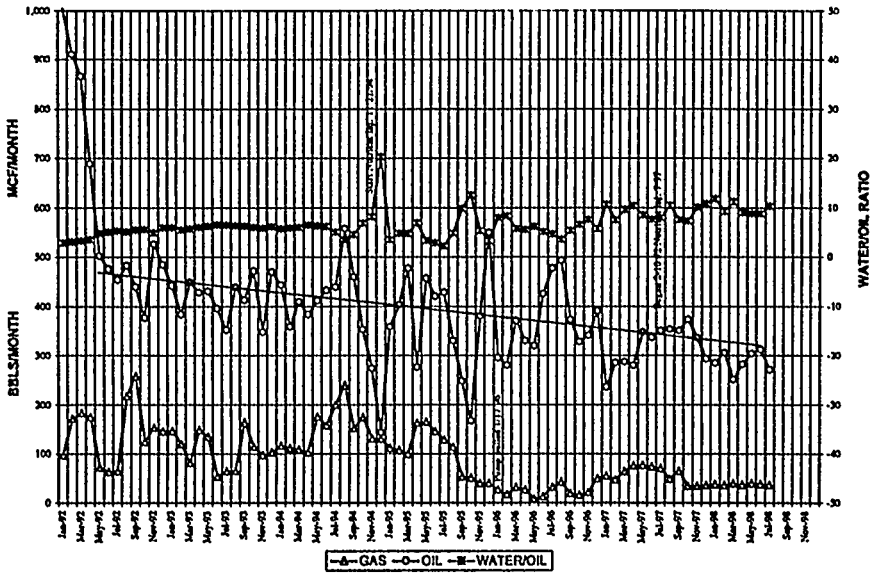


Figure A1. Well 2-11 No. 1 (2-14 No. 1, 2-6 No. 1, and 2-10 No. 2 Nutrient Injectors).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is the northernmost well in Test Pattern 1 and the southernmost well in Test Pattern 4. It is situated north of test injector well 2-14 No. 1 and south of test injector well 2-6 No. 1. Approximately five months after beginning nutrient injection, there was an appreciable increase in oil production and the rate of decline in oil production became considerably less. WOR remained steady most of the time, then started to increase but at a lower rate. When production from well 2-11 No. 3 began, there was a steady drop in oil production (from Jan. to Sept. 1997). However, when well 2-11 No. 3 was shut-in, production began a steady increase. When the tracer study was performed in April of 1994, no evidence of communication with the injector well (well 2-14 No. 1) was obtained. It must be remembered, however, that this well could have easily been influenced by the injector well (well 2-6 No. 1) in Test Pattern 4.

Examination of the G.C. data on production fluid from this well fail to indicate an appreciable increase in the ratio of 1:4. The ratio of 1:4 dropped 45% from 3.17 to 1.73 from 1995 to 1996, respectively, and remained essentially constant at 1.60 in 1997. In 1998, however, the 1:4 ratio increased 26% to 2.01. While the increased oil production from this well prior to the drilling of well 2-11 No. 3 does not appear to be the result of the inclusion of previously bypassed oil as shown by GC analysis, it must be the result of some exogenous influence and the only known influence was microbial growth in the reservoir due to nutrient injection into either and/or both of the nearby test injectors.



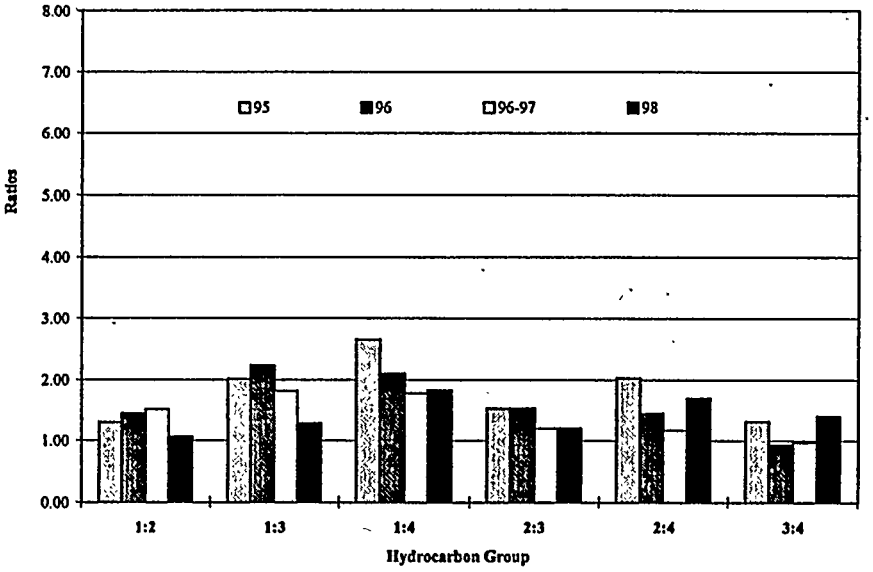
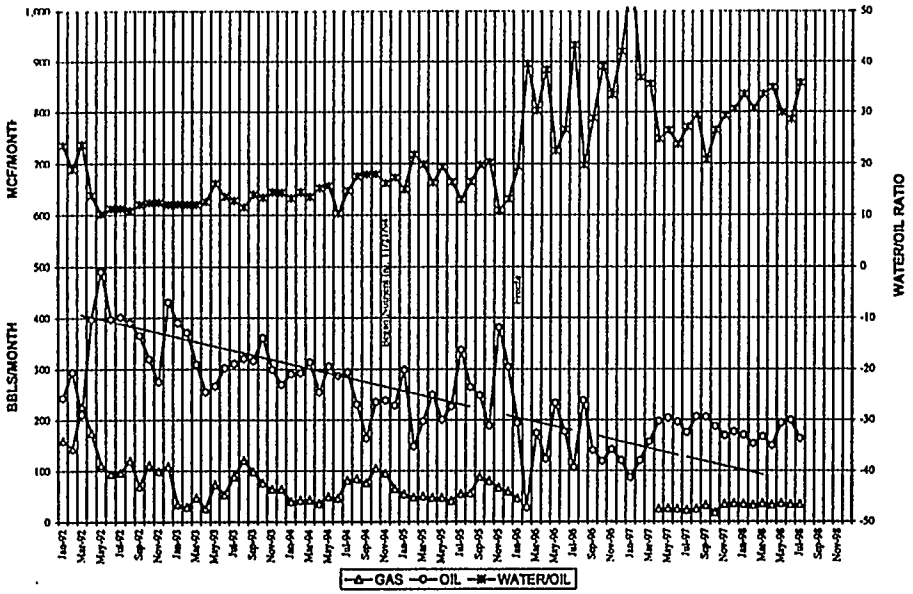


Figure A2. Well 2-15 No. 1 (2-14 No. 1 and 2-10 No. 2 Nutrient Injectors).

This well was classified as a questionable response to MPPM as shown in Table 8.

This well is in Test Pattern 1, due east of test injector well 2-14 No.1 and southeast of injector well 2-10 No. 1 that was not in the original experimental plan but did receive nutrient injections from July 1997 through June 1998. In the tracer test conducted in April 1994, communication between this well and injector well 2-14 No. 1 was demonstrated in one sample after seven months but never again so the connection between this well and the injector well 2-14 No. 1 did not appear to be consistent. Fluid production from this well has been erratic with no evidence of enhanced recovery due to microbial activity in the reservoir. The G.C. data from fluid out of his well tend to confirm this conclusion. Figure 4 shows that the ratio of 1:4 was rather low in 1995 as would be expected in a well that had been producing for years and declined from 2.65, to 2.10, to 1.78, to 1.82 in 1995, 1996, 1997, and 1998, respectively. The quantity of group1 compounds declined while the quantity of group 4 compounds increased.



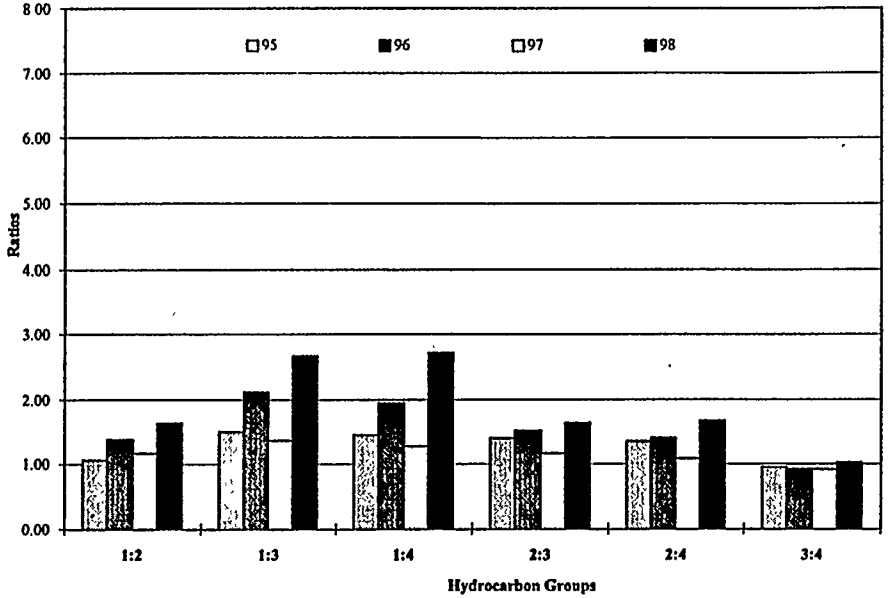
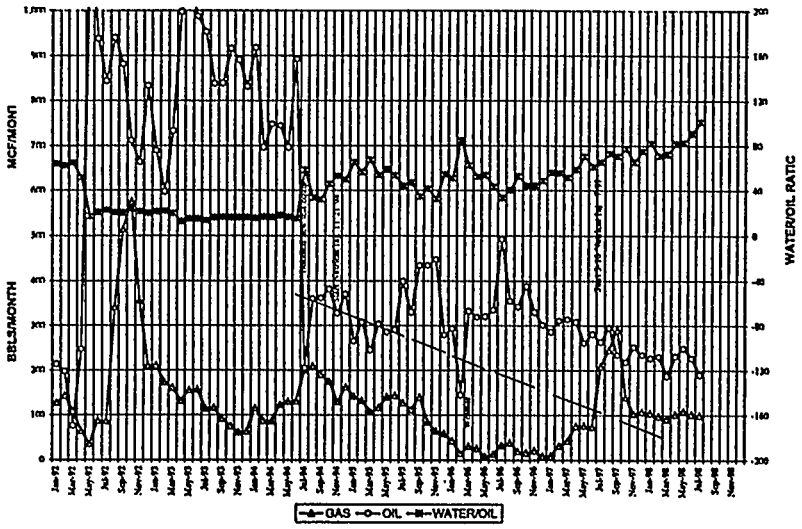


Table A3: Well 11-3 No. 1 (2-14 No. 1 and 11-5 No. 1 Nutrient Injectors).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Test Pattern 1 and Test Pattern 3 and is situated almost due south of test injector well 2-14 No. 1 and northeast of test injector well 11-5 No.1. Oil production from this well was erratic until January 1997 when it increased and then remained essentially constant and WOR has generally remained steady. The ratio of 1:4 rose from 1.44 in 1995 to 1.95 in 1996 but fell back to 1.28 in 1997. In 1998 the ratio of 1:4 was 2.72 which is greater than a 100% increase. The quantity of group 1 compounds increased while the quantity of group 4 compounds decreased. These data definitely indicate the presence of bypassed oil in the produced fluid. Interestingly enough, the tritium injected into injector well 2-14 No. 1 in April 1994 required 18 months before it appeared in this well (well 11-3 No. 1). Therefore, it is not surprising that manifestation of the microbial growth in the reservoir was not apparent until 1998.



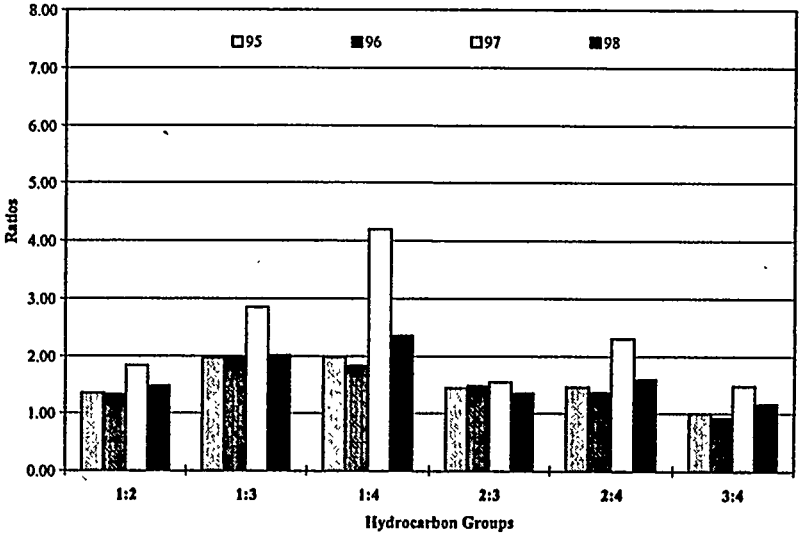
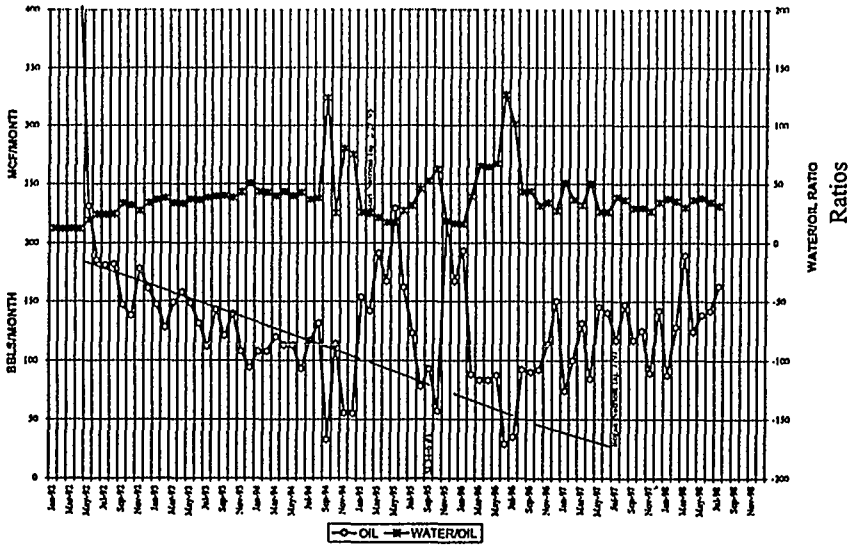


Table A4: Well 2-13 No. 1 (2-14 No. 1 11-5 No. 1, and 3-16 No. 1 Nutrient Injectors).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Test Pattern 1 and Test Pattern 3. It is situated due west of test injector well 2-14 No. 1 and north of test injector well 11-5 No. 1 and east of test injector 3-16 No. 1 that was not in the original experimental plan but did receive nutrients from July 1997 through June 1998. In the tracer test conducted in April 1994, communication between this well and test injector 2-14 No. 1 was demonstrated in six months. Approximately six months after beginning the nutrient injection, there was an increase in oil production and the rate of decline in oil production decreased. The WOR remained steady, but recently has begun to increase slightly. The presence of bypassed oil was clearly demonstrated in 1997 when the ratio of 1:4 increased over 100% from 1.98 to 4.20 from 1995, to 1997, respectively. The amount of group 1 compounds increased while the amount of group 4 compounds decreased from 1995-96 to 1997-98.



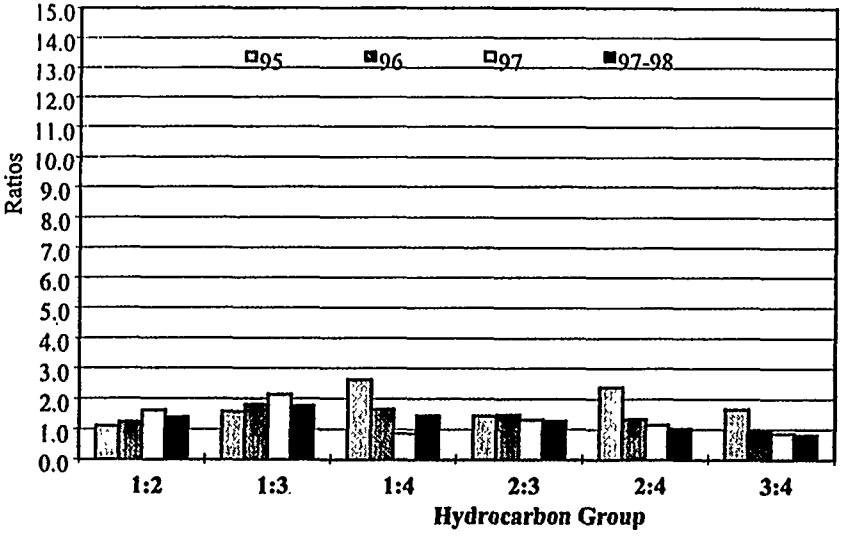
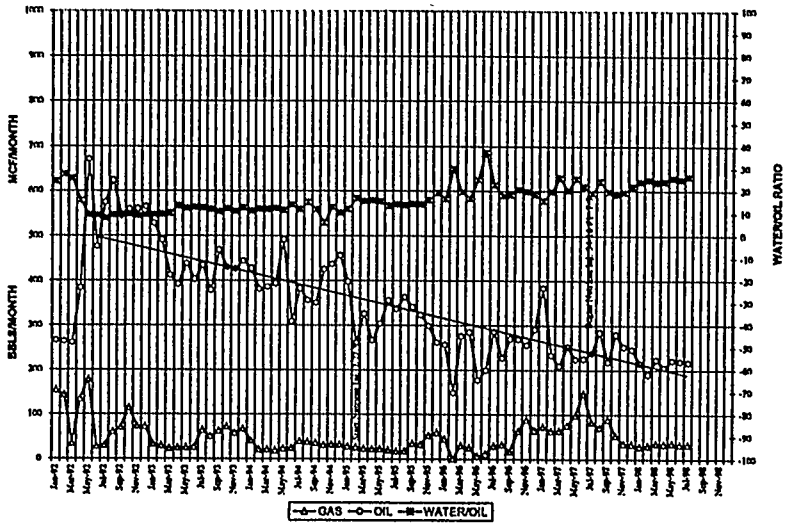


Table A5: Well 34-7 No. 2 (34-9 No. 2 and 34-7 No. 1 Nutrient Injectors).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is located in Test Pattern 2 and in Control Pattern 2. It is situated north of test injector well 34-9 No. 2 and southeast of control injector well 34-7 No. 1 that was converted into a test injector well from July 1997 through June 1998. During the last 2 years, there was an increase in oil production and the WOR declined slightly. The increased oil production in this well does not appear to be due to the influx of previously unswept oil into the production fluid as determined by GC since there were no significant increases in the ratio of 1:4. Values for the 1:4 ratios were 3.02, 1.65, 1.86, and 1.44 for 1995, 1996, 1997, and 1998 respectively.



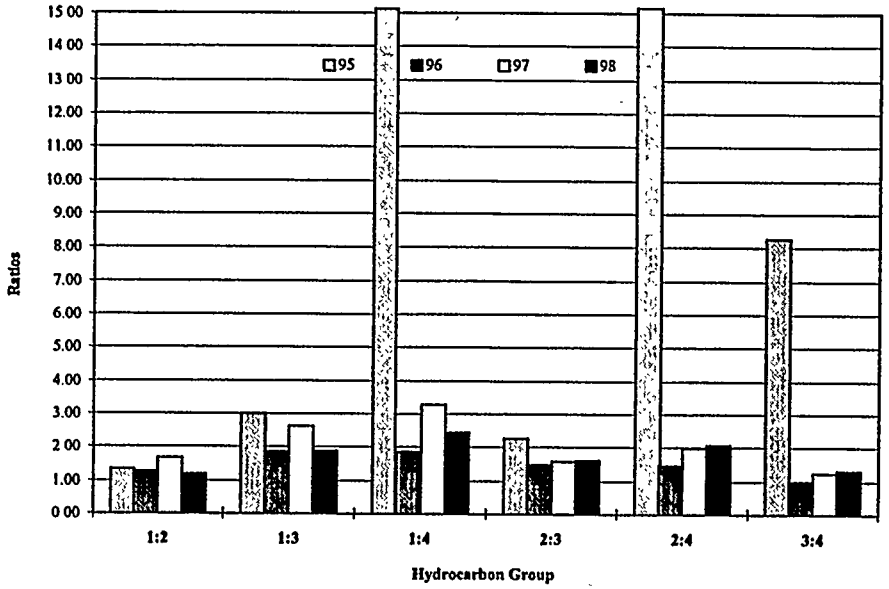
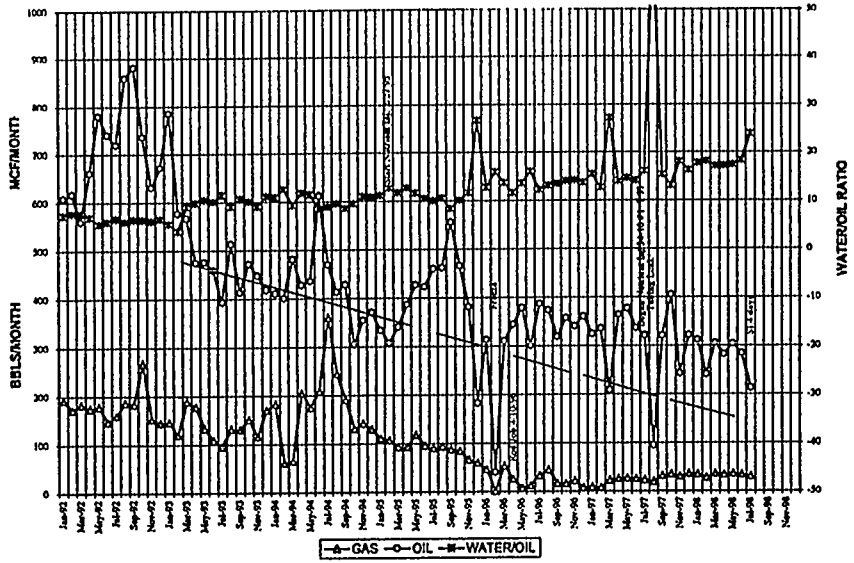


Table A6: Well 34-16 No. 2 (34-9 No. 2 and 34-16 No. 1 Nutrient Injectors)

This well was classified as a questionable response to MPPM as shown in Table 8.

This well is located in Test Pattern 2 and is situated southeast of test injector well 34-9 No. 2. It is almost due north of injector well 34-16 No. 1 that was not in the original experimental plan but did receive nutrients from July 1997 through June 1998. Oil production demonstrated a natural decline until July 1997 after which time the production decline decreased somewhat. The ratio of 1:4 increased from 1.85 to 3.27, a 77% increase, between 1996 and 1997 indicating the presence of previously bypassed oil in the production fluid from this well.



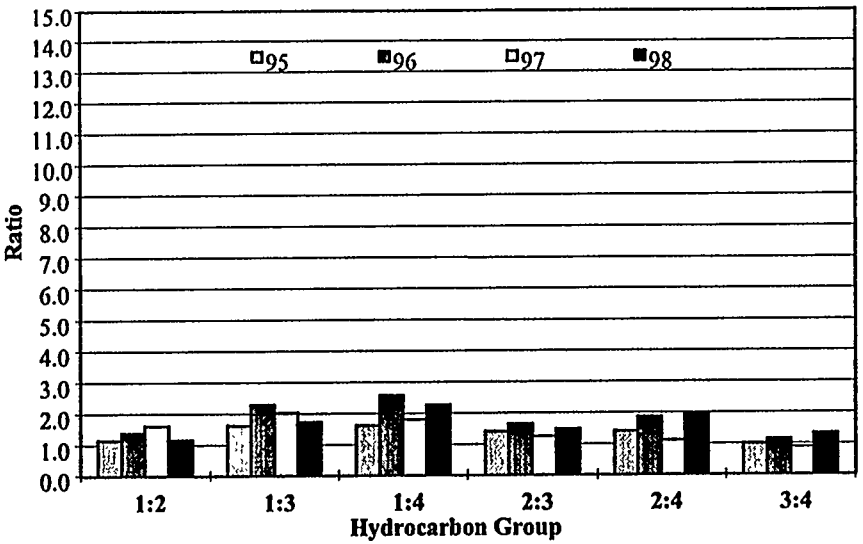
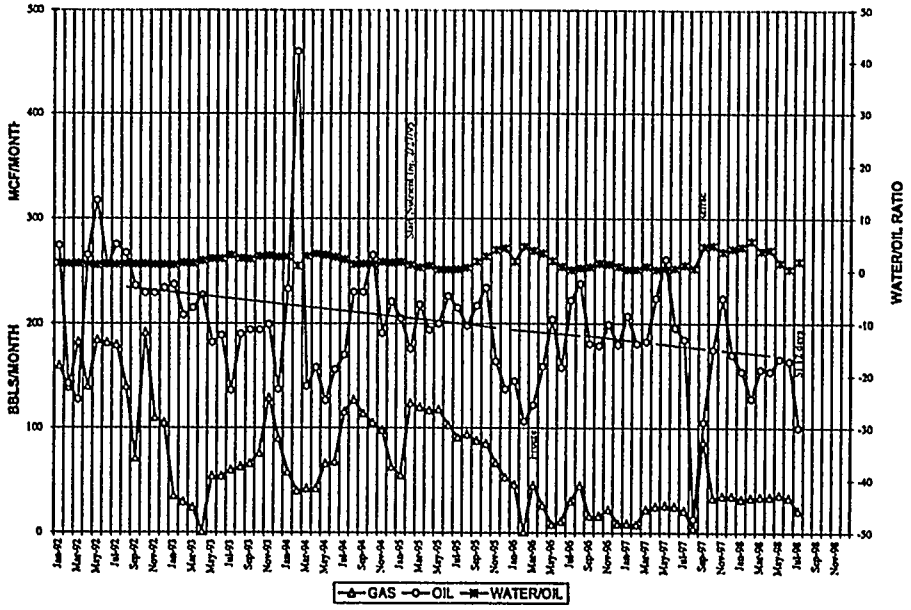


Table A7: Well 34-15 No. 1 (34-9 No. 2 and 34-16 No. 1 Nutrient Injectors).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is located in Test Pattern 2 and Control Pattern 3. It is situated southwest of test injector well 34-9 No. 2 and west northwest of injector well 34-16 No. 1 that was not in the original experimental plan but did receive nutrients from July 1997 through 1998. Approximately 15 months after beginning the nutrient injection, there was an increase in oil production and subsequently the oil production rate declined at a lesser rate. WOR remained steady. The ratio of 1:4 increased 60% (1.61 to 2.58) from 1995 to 1996 as a result of an increase in group 1 compounds and a decrease in group 4 compounds. This ratio of 1:4 decreased from 2.58 to 1.80 in 1997 (28% decrease) but rose to 2.26 (a 26% increase) in 1998. These G.C. data indicate the appearance of bypassed oil in production fluid from this well.



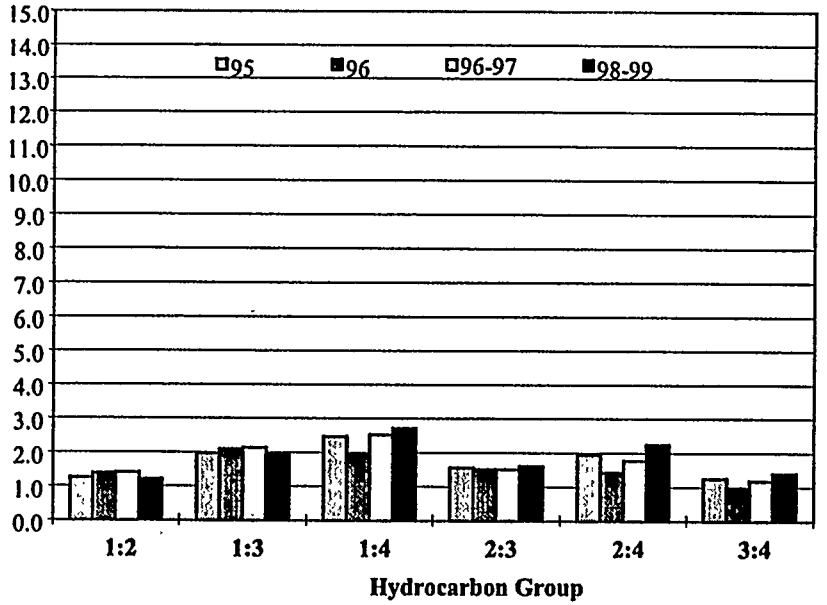
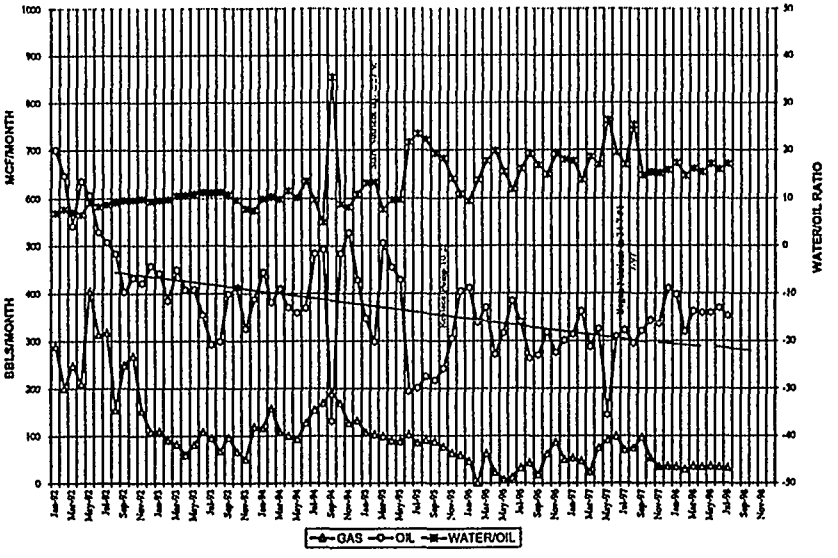


Table A8: Well 34-15 No. 2 (34-9 No. 2 Nutrient Injector).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Test Pattern 2 and Control Pattern 3. It is situated west southwest of test injector well 34-9 No. 2. Approximately 16 months after beginning the nutrient injection, there was a slight increase in oil production and subsequently oil production remained steady except for the period in which the well was refractured (Aug. 1997). WOR remained steady except for the period in which the well was refractured. The ratio of 1:4 fluctuated from 2.46 to 1.96 to 2.52 to 2.70 for 1995, 1996, 1997, and 1998, respectively, and consequently did not clearly indicate the presence of bypassed oil.



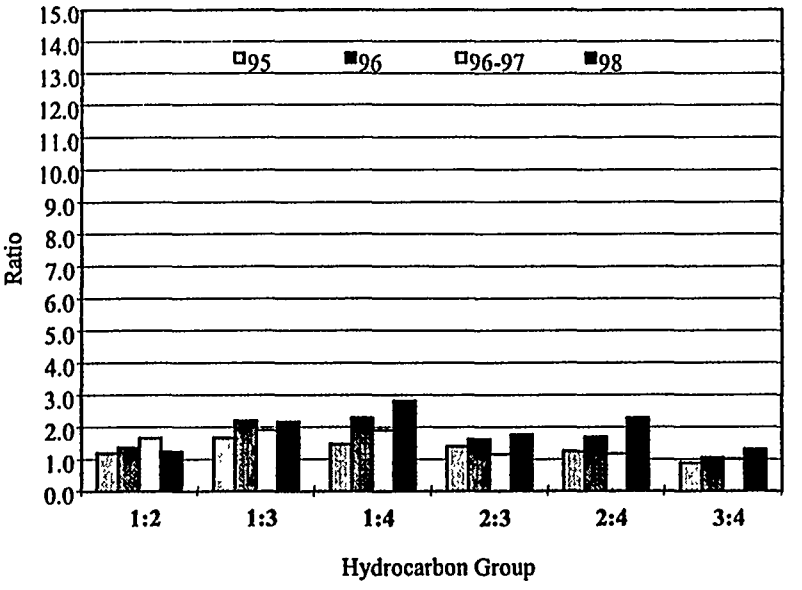
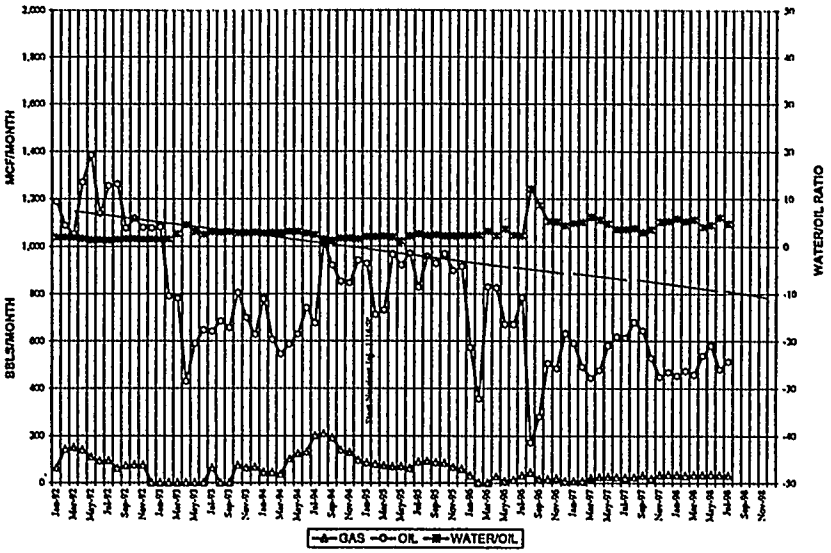


Figure A9: Well 34-10 No. 1 (34-9 No. 2 and 34-7 No. 1 Nutrient Injectors).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Test Pattern 2 and Control Pattern 2. It is situated northwest of test injector well 34-9 No. 2 and south southwest of control injector well 34-7 No. 1 that received nutrients from July 1997 through June 1998. Oil production declined until Sep. 1997, at which time it increased and WOR declined. The low oil production in 1995 is reflected in the low ratio of 1:4 (1.48). When oil production increased in 1996 the ratio of 1:4 also increased to 2.28 or a 54% increase. There was a 19% decrease in this 1:4 ratio in 1997 but another increase of 47% (from 1.91 to 2.81) in 1998. These data suggest an influx of bypassed oil in the production fluid from this well.



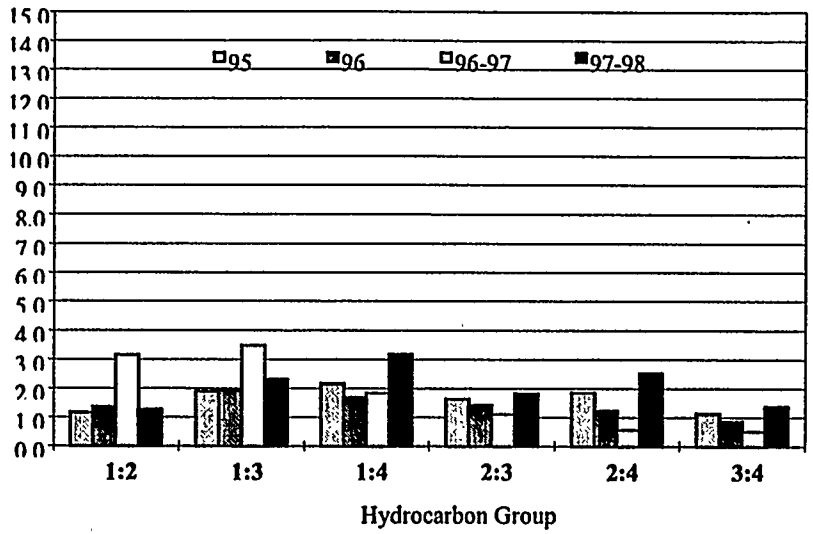


Figure A10: Well 10-8 No. 1 (11-5 No. 1 Nutrient Injector).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Test Pattern 3 and is situated southwest of test injector well 11-5 No. 1. This well had mechanical problems. While oil production did not show a positive response initially, there were indications (aliphatic profile and petrophysical properties) that there had been a change in the characteristics of the produced oil suggesting new oil was being recovered. Both production and WOR have held steady since late 1997. The ratio of 1:4 went from 2.15 to 1.68 to 1.83 in 1995, 1996, and 1997, respectively. In 1998, however, the ratio of 1:4 increased 74% to 3.18 which clearly indicates the recovery of bypassed oil in the production fluids.

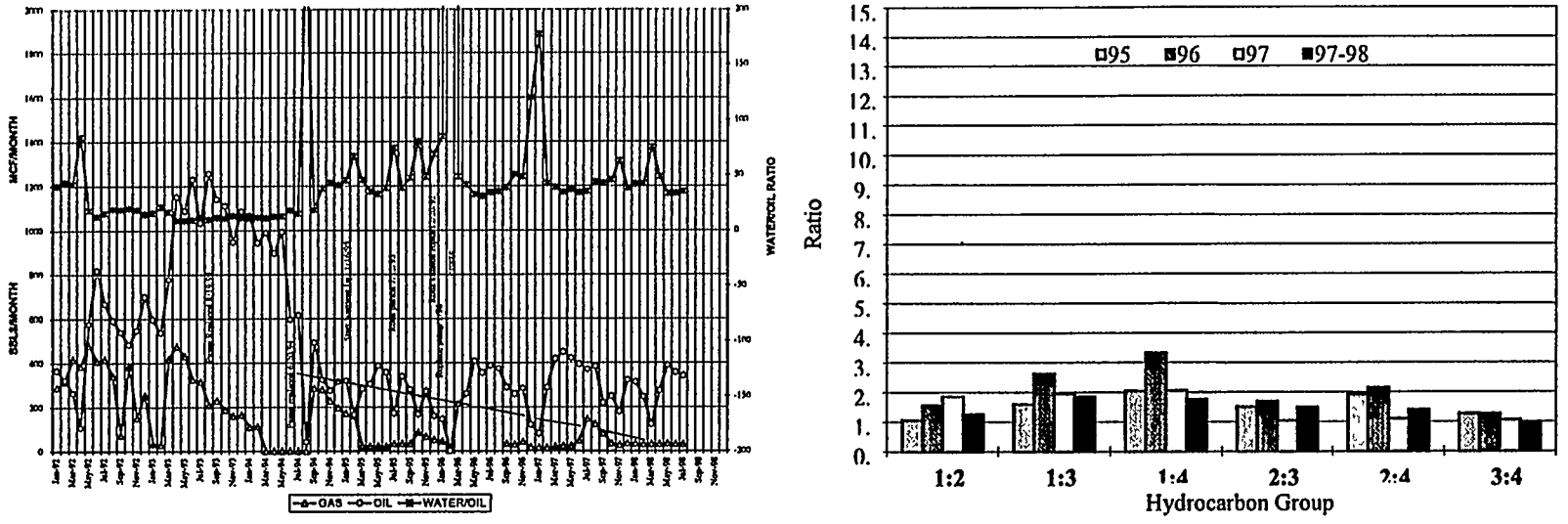
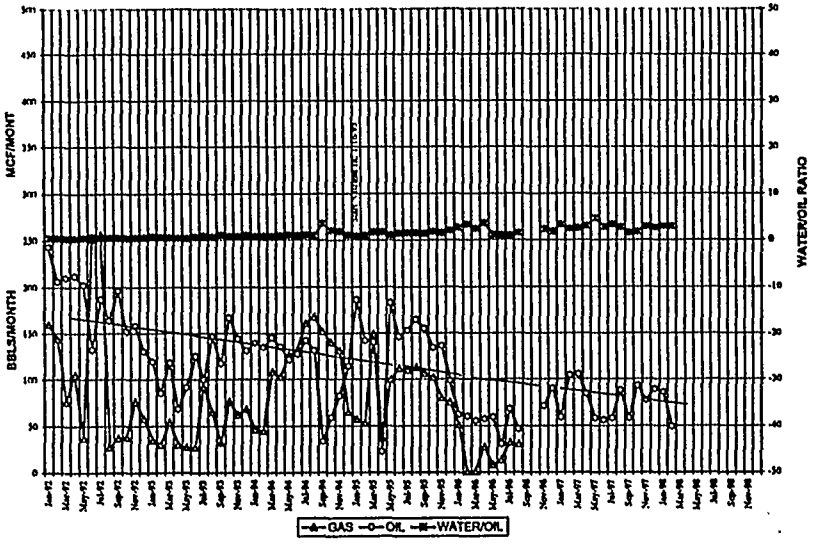


Figure A11: Well 11-6 No. 1 (11-5 No. 1 Nutrient Injector).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Test Pattern 3 and is situated east of test injector well 11-5 No. 1. This well had mechanical problems. Approximately 15 months after beginning the nutrient injection, the oil production rate increased and subsequently held steady. WOR held steady. The ratio of 1:4 increased from 2.04 to 3.33 (63%) between 1995 and 1996 but then has steadily declined to 2.06 and 1.76 in 1997 and 1998, respectively. The big increase in oil production coincides with the big increase in the ratio of 1:4 and is characteristic of the presence of bypassed oil in the production fluid.



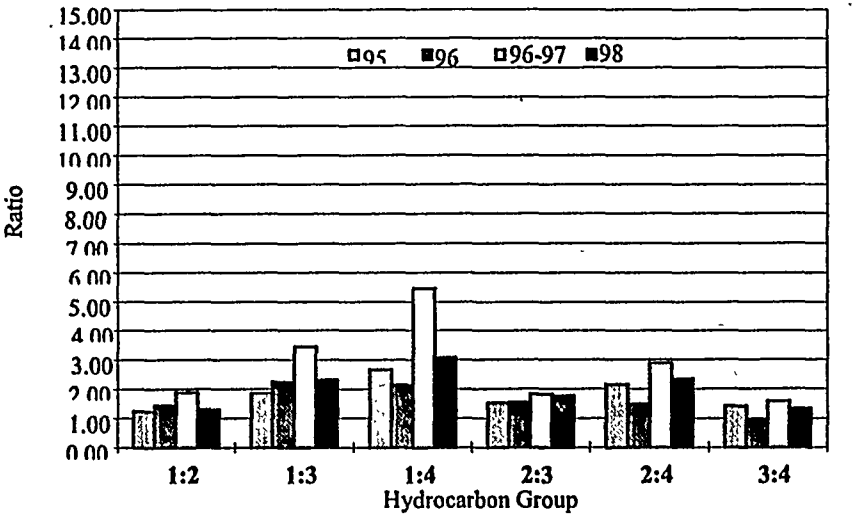
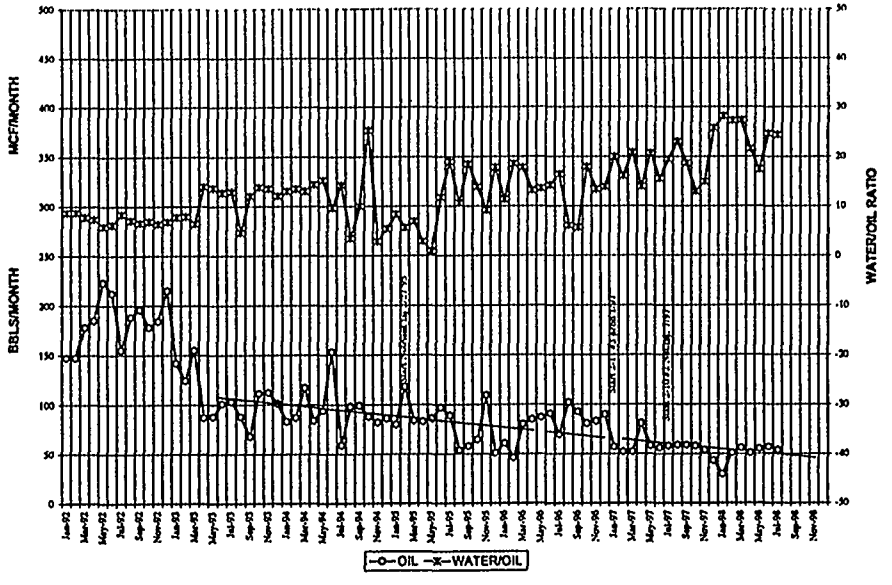


Figure A12: Well 11-4 No. 1 (11-5 No. 1 Nutrient Injector).

This well was classified as a no response to MPPM as shown in Table 8.

This well is in Test Pattern 3 and is situated north northeast of test injector well 11-5 No. 1 and southeast of injector well 3-16 No. 1 that was not in the original experimental design but did receive nutrients from July 1997 through June 1998. This well has exhibited natural decline in oil production with a concurrent increase in WOR. The ratio of 1:4 dropped from 2.66 to 2.15 (19%) between 1995 and 1996 but increased (153%) in 1997 due to an increase in group 1 compounds and a decrease in group 4 compounds. This increase in the 1:4 ratio definitely indicates the presence of a large percentage of bypassed oil in the produced fluid. In 1998 the ratio of 1:4 dropped to 3.08 which would be expected as time goes by, but is still relatively high.



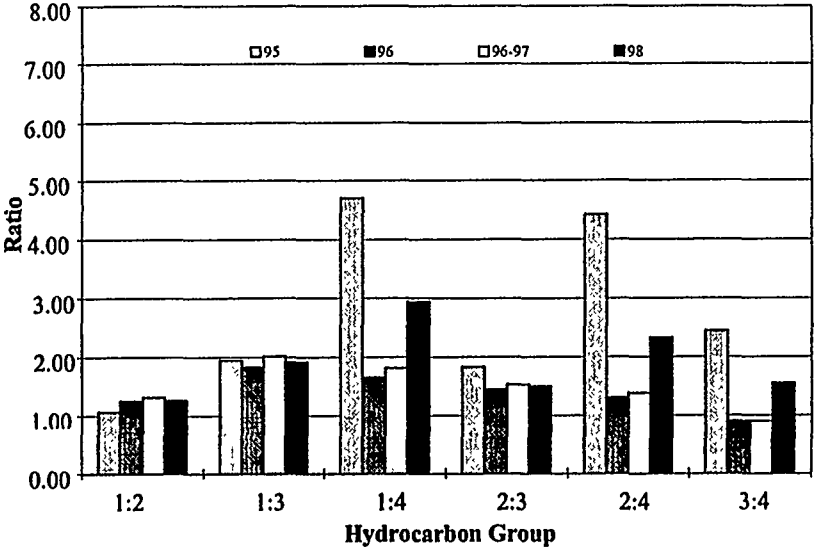


Figure A13: Well 2-11 No. 2 (2-6 No. 1 and 2-10 No. 2 Nutrient Injector).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Test Pattern 4 and is situated southeast of test injector 2-6 No. 1 and north of test injector 2-10 No. 2 that was not in the original experimental plan but did receive nutrients from July 1997 through June 1998. Approximately 13 months after beginning the nutrient injection, oil production increased until Jan. 1997 when well 2-11 No. 3 began producing and production from well 2-11 No. 2 began to decline. After well 2-11 No. 3 was shut-in in Aug. 1997, oil production stopped its decline and WOR remained steady. (Well 2-11 No. 3 was drilled in Nov. 1996 and is located west northwest of well 2-11 No. 2.) The ratio of 1:4 in well 2-11 No. 2 dropped from 2.52 to 1.64 between 1995 and 1996 and rose only slightly (11%) in 1997 to 1.82. In 1998, however, the ratio climbed to 2.94, probably due to the impact of well 2-11 No. 3. Therefore, this increase in the 1:4 ratio may not be due entirely to microbial activity alone.

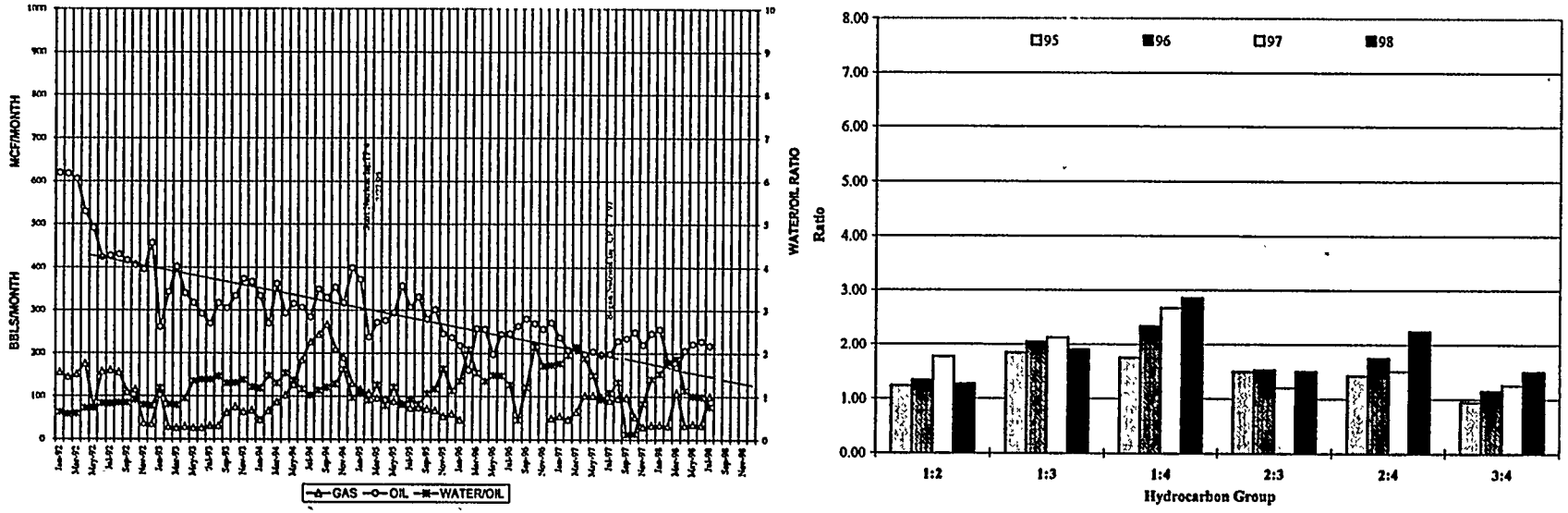
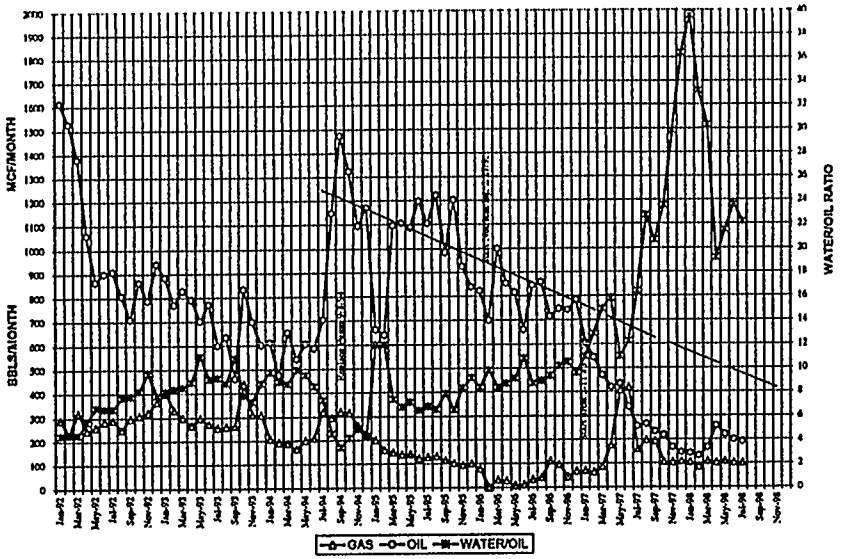


Figure A14: Well 2-3 No. 1 (2-6 No. 1 and 2-4 No. 1 Nutrient Injectors).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Test Pattern 4 and Control Pattern 1. It is situated almost due north of test injector well 2-6 No. 1 and east of control injector well 2-4 No. 1 that was converted to a test injector well from July 1997 through June 1998. This well had shown a positive response and oil production had been consistently above the projected amount. Approximately 24 months after beginning the nutrient injection, WOR began to drop sharply. This well also benefited from the nutrient injection in control injector 2-4 No. 1. The ratio of 1:4 has steadily climbed from 1995 through 1998 showing an increase of 63% over that time period caused by an increase in group 1 compounds and a decrease in group 4 compounds. These data suggest a small but steady increase in previously bypassed oil in the production fluid.



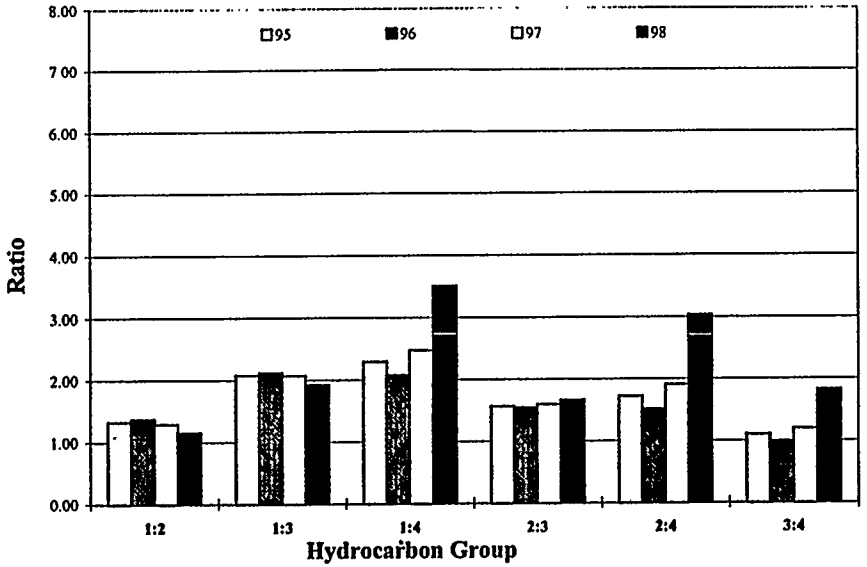


Figure A15: Well 2-5 No. 1 (2-6 No. 1, 2-4 No. 1, and 2-12 No. 1 Nutrient Injectors).

This well was classified as a no response to MPPM as shown in Table 8.

This well is in Test Pattern 4 and Control Patterns 1, and 4. It is situated west of test injector well 2-6 No. 1, south of control injector well 2-4 No. 1 that was converted to a test injector well from July 1997 through June 1998. It is due north of injector well 2-12 No. 1 that was not in the original experimental design but received nutrients from July 1997 through June 1998. This well had continued on a natural decline until approximately Nov. 1996 when production fell dramatically due to the production from newly drilled well 2-5 No. 2. WOR continued to increase. The ratio of 1:4 stayed essentially constant from 1995 through 1997 (2.29, 2.07, and 2.47, respectively) but increased 42% to 3.5 in 1998 caused by a drop in group 4 compounds. The new wells drilled nearby in late 1996 obviously impacted the performance of this well and consequently no meaningful conclusions about its performance can be drawn.

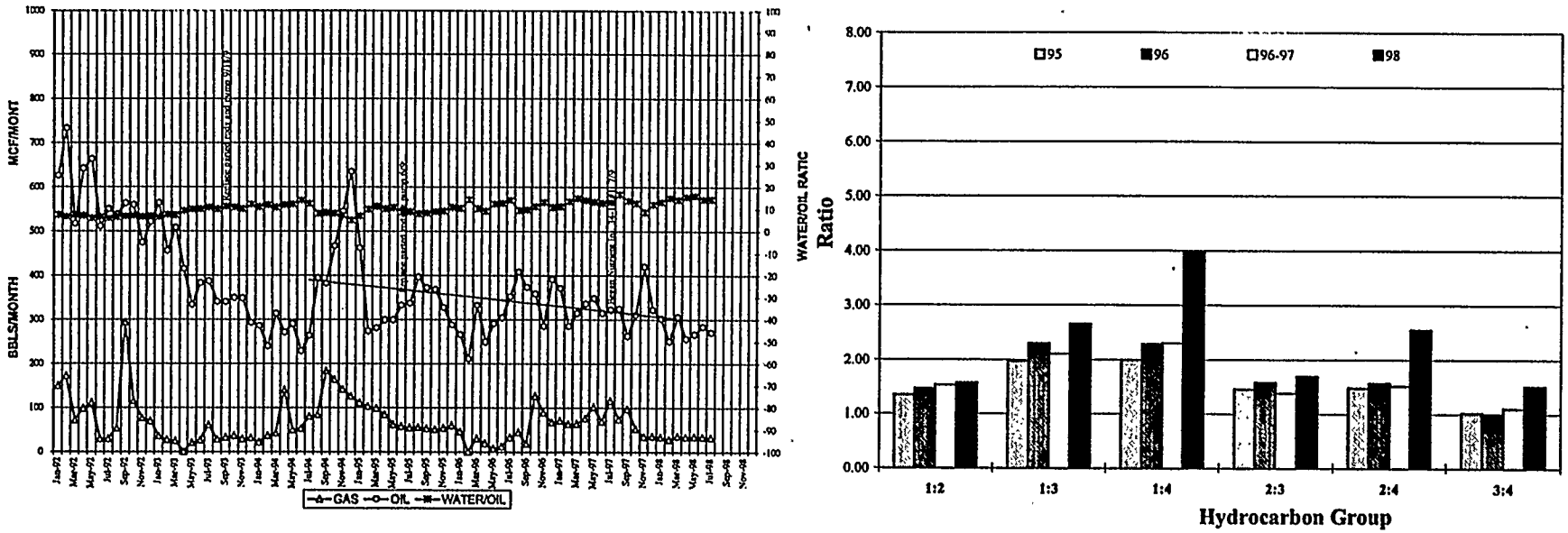
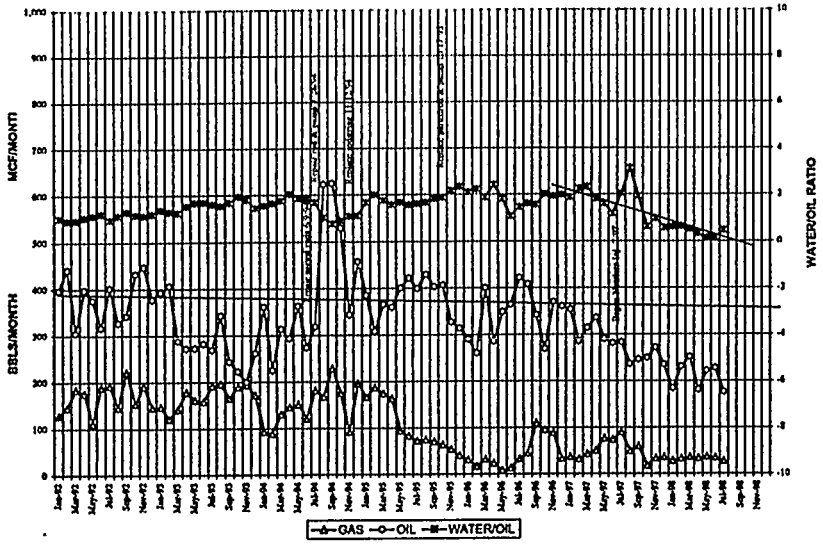


Figure A16: Well 35-13 No. 1 (34-16 No. 1 and 2-4 No. 1 Nutrient Injectors)

This well was classified as natural decline as shown in Table 8.

This well is in Control Pattern 1 and is situated due north of control injector well 2-4 No. 1 that was converted into a test injector from July 1997 to July 1998. Injector well 34-16 No 1, not included in the original experimental design, is due west of well 35-13 No. 1 and received nutrients from July 1997 through June 1998. The oil production rate has shown a steady decline since 1995 although the rate of decline is considerably less than it was prior to that time. This change in rate of decline is probably due to mechanical work on the well. The ratio of 1:4 remained virtually steady for 1995, 1996, and 1997 at 2.0, 2.28, and 2.31, respectively. In 1998, however, the ratio of 1:4 increased 75% to 4.0, strongly suggesting the presence of bypassed oil in the produced fluid even through total production of oil has not increased.



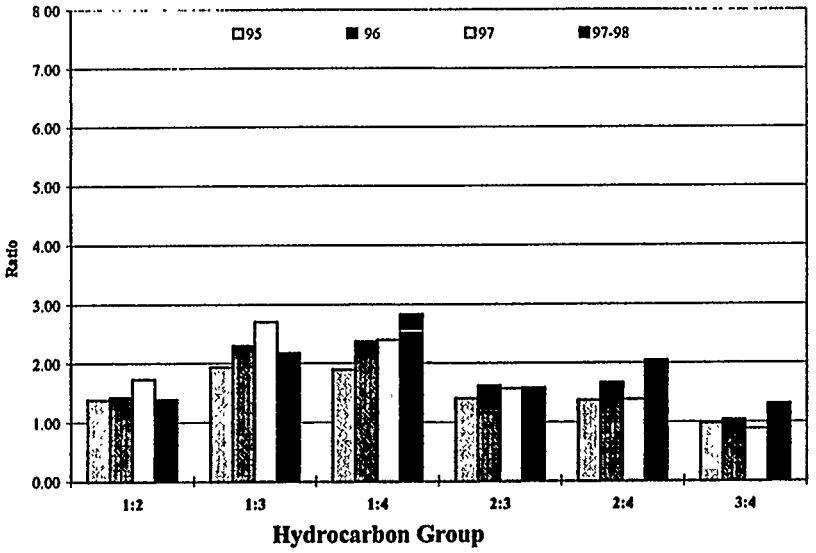


Figure A17: Well 3-1 No.1 (2-4 No. 1 and 34-16 No. 1 Nutrient Injectors).

This well was classified as natural decline as shown in Table 8.

This well is located in Control Patterns 1,3, and 4. It is situated west of control injector well 2-4 No. 1 that was converted into a test injector from July 1997 through June 1998. It is due south of injector well 34-16 No. 1 that was not in the original experimental plant but did receive nutrients from July 1997 through June 1998. This well had continued its natural decline up until Aug. of 1997 when WOR began an appreciable decline which may reflect a response to nutrient injection into two nearby injectors (34-16 No. 1 and 2-4 No. 1). The ratio of 1:4 did not show any dramatic changes indicating bypassed oil in the production fluid but rather showed a steady increase from 1.89, to 2.11, to 2.39, to 2.83, for 1995, 1996, 1997, and 1998, respectively.

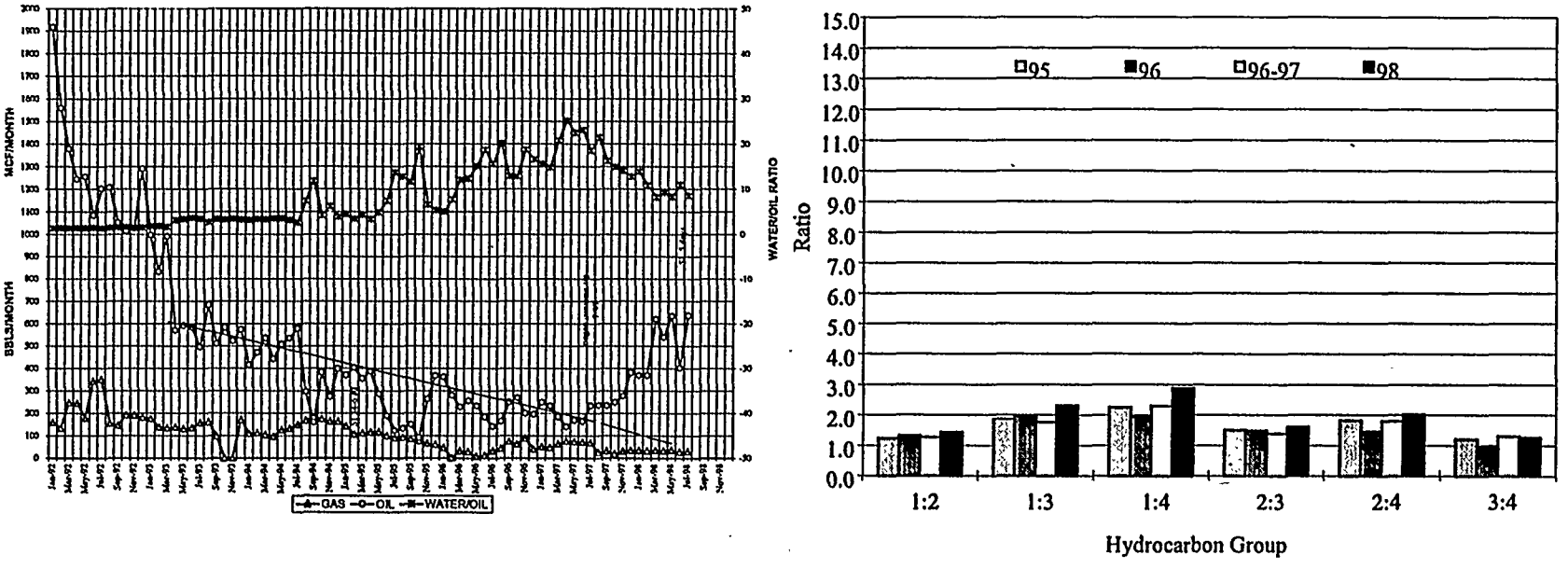
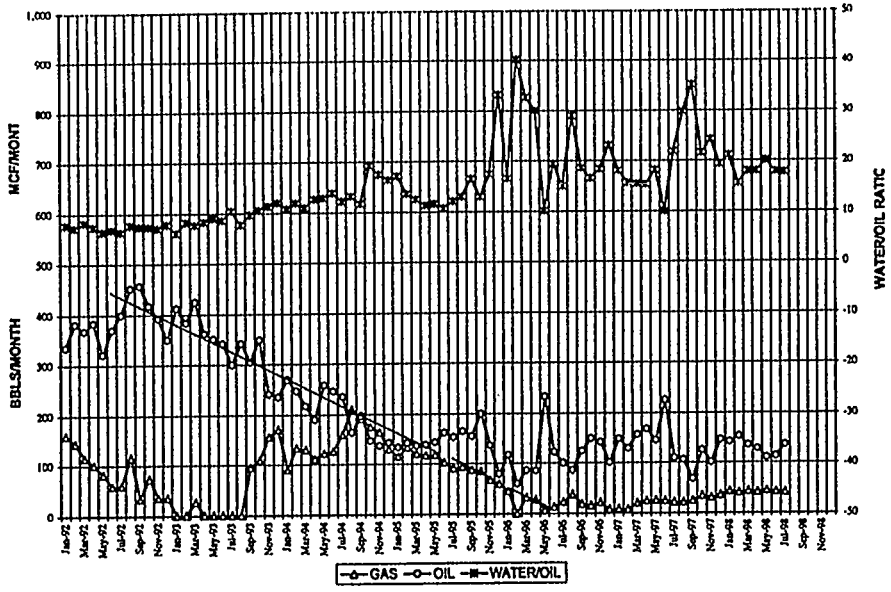


Figure A18: Well 34-2 No. 1 (34-7 No. 1 Nutrient Injectors)

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Control Pattern 2 and is situated due north of control injector well 34-7 No. 1 which received nutrients from July 1997 through June 1998. This well was exhibiting a natural decline until July 1997 at which time oil production began to increase appreciably due to nutrient injection into 34-7 No. 1. WOR decreased. The changes in the ratio of 1:4 were not nearly as dramatic as the large increase in oil production that began about four months after the control injector well started to receive nutrients. The ratio of 1:4 decreased 14% from 1995 to 1996 (2.25 to 1.94) but was back up to 2.30 in 1997. In 1998 the ratio increased to 2.90 (26% increase) due to an increase in group 1 compounds and a decrease in group 4 compounds.



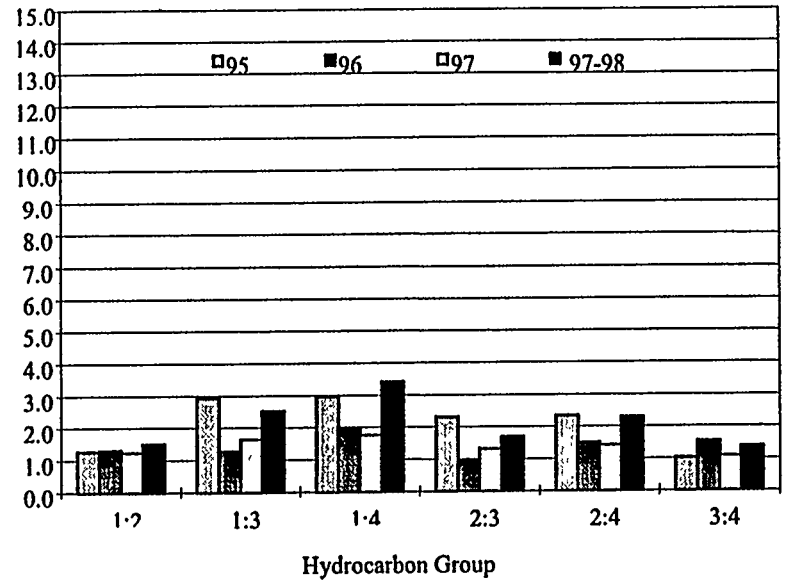


Figure A19: Table 3-3 No. 1 (3-2 No. 1 Injector).

This well was classified as natural decline as shown in Table 8.

This well is in Control Pattern 3 and is the westernmost well in this study. Oil production has remained essentially steady since May 1995 due to increased water injection in Control Injection well 3-2 No. 1. WOR increased. The ratio of 1:4 dropped from 2.98, to 2.12, to 1.76, in 1995, 1996, and 1997, respectively. Surprisingly, this ratio jumped to 3.42, a 94.3% increase, in 1998. These data suggest that some of the produced fluids are coming from previously bypassed oil and is result of the increased water injection initiated in 1995 or a reflection of other changes in the reservoir due to microbial growth.

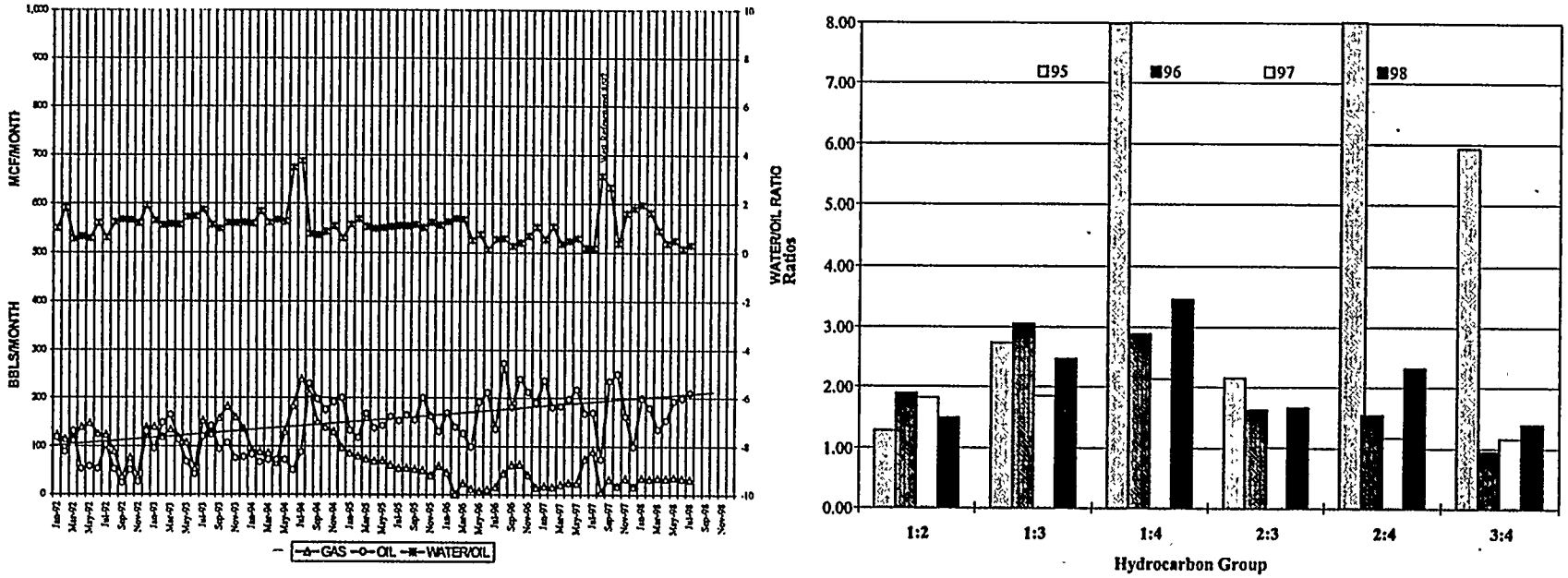
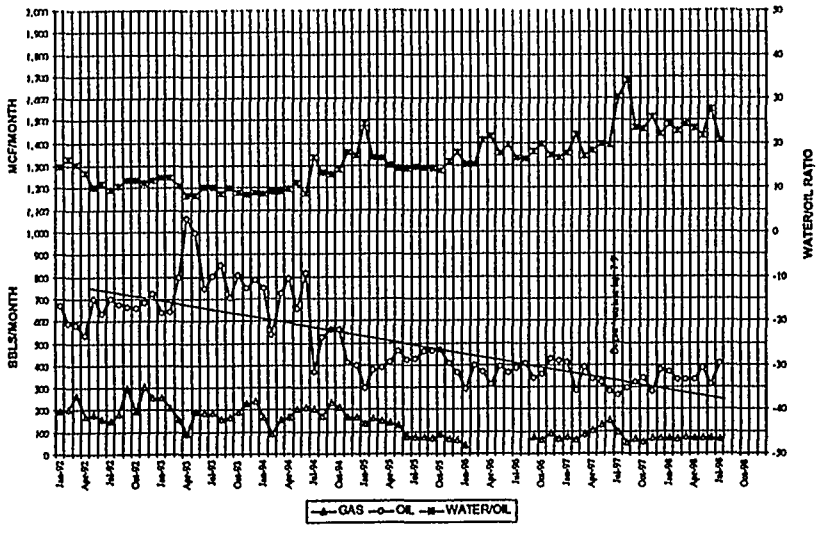


Figure A20: Well 3-1 No. 2 (3-2 No. 1 and 3-8 No. 1 Injectors).

This well was classified as a positive response as shown in Table 8 but was due to increased water injection in a nearby injector and not to MPPM.

This well is in Control Patterns 3 and 4. The positive response in oil production was due to an increase in water injection, not MEOR. WOR fluctuated due to refracturing of the well. Between 1996 and 1997 the ratio of 1:4 dropped 26%. As was the case with well 3-3 No. 1, the ratio of 1:4 exhibited a large increase (62%) in 1998, probably for the same reason(s) given for well 3-3 No. 1.



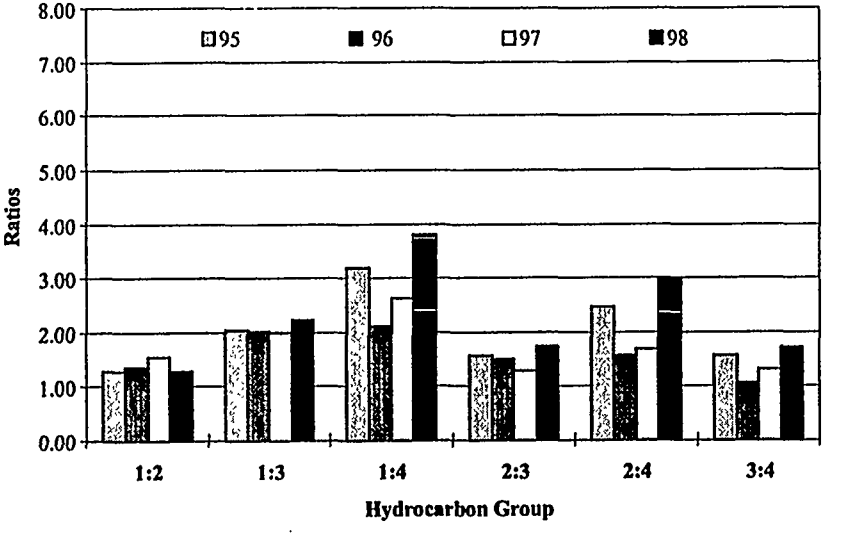


Figure A21: Well 3-9-1 (2-12 No. 1 and 3-16 No. 1 Nutrient Injectors).

This well was classified as a positive response to MPPM as shown in Table 8.

This well is in Control Pattern 4 and is situated west-southwest of injector well 2-12 No. 1 and north of injector well 3-16 No.1. Neither of these injectors was included in the original experimental plan but both received nutrients from July 1997 through June 1998. Oil production rate increased after the start of nutrient injection in 2-12 No. 1 and 3-16 No. 1. WOR leveled off and declined. The ratio of 1:4 decreased from 3.19 to 2.12 then rose slightly to 2.31 in 1995, 1996, and 1997, respectively. In 1998, however, the ratio rose 64% to 3.81. These data clearly indicate the impact of microbial activity in causing an increase in the amount of previously bypassed oil in the production fluid.

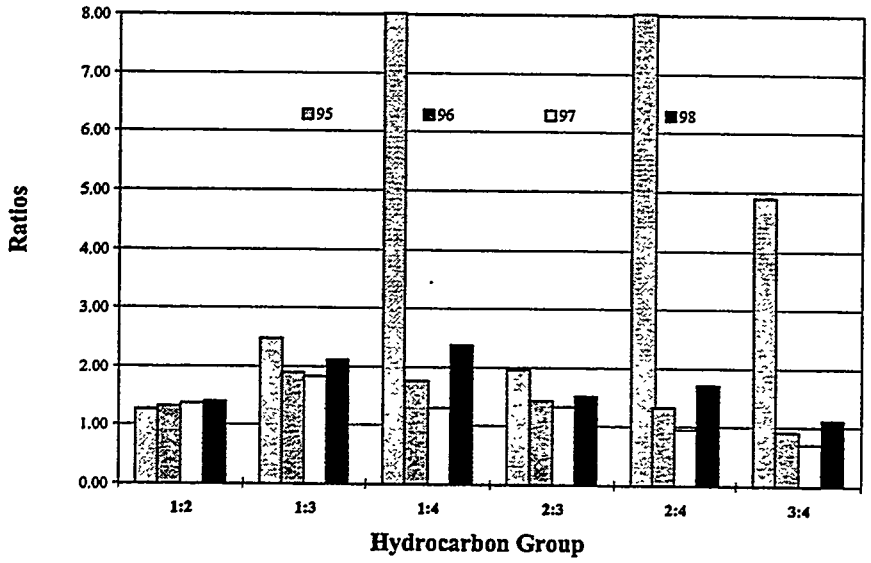


Figure A22. Well 34-6 No. 3.

This well was drilled in April 1994 in an area of the field that had not been swept by the waterflood. As may be seen, the ratio of group 1 compounds to group 4 compounds is extremely high (12.08) but dropped dramatically to 1.77 due to a 22% drop in group 1 compounds and a large increase (5.3x) in group 4 compounds. The ratio dropped even further to 1.30 in 1997 but increased to 2.38 in 1998. This 83% increase was due to an increase of 18% in group 1 compounds with a drop of 35% in group 4 compounds. The drop in the ratio of 1:4 in 1996 and 1997 was to be expected for a newly drilled well and generally this trend should continue or at least stabilize in subsequent years. Therefore, the increase of 35% in the 1:4 ratio in 1998, coupled with the steady increase in oil production suggests that production is being influenced by some exogenous force. The most likely influences would have been either (1) the shut-in of nearby well 34-6 No. 1 or (2) the nutrient additions into injector well 34-7 No. 1.

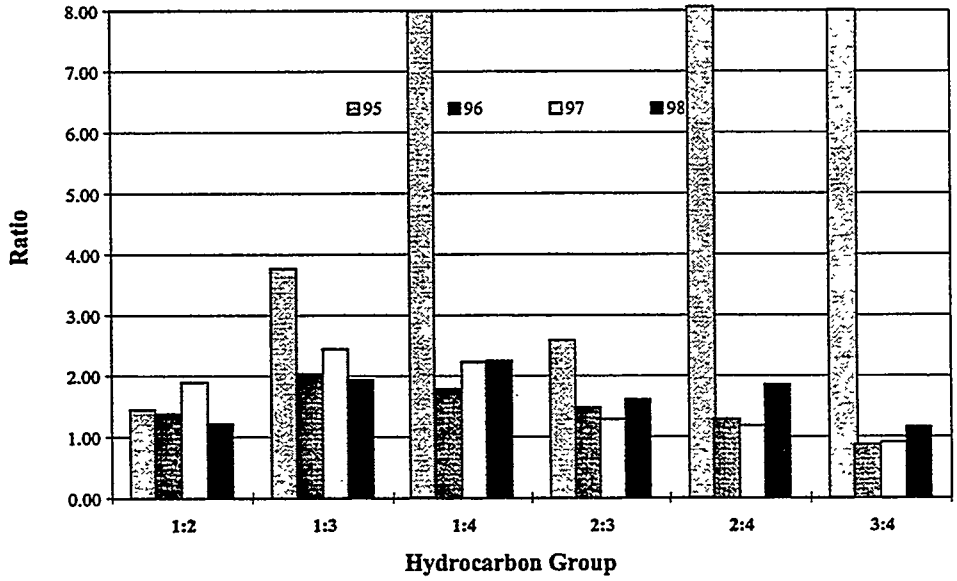


Figure A23. Well 34-3 No. 2

This well was drilled in 1994 also in an area of the field that had been only partially swept by the waterflood. The ratio of 1:4 was 1.78 in 1996 and leveled off at 2.23 and 2.25 for 1997 and 1998. This is the type of pattern expected for a well not influenced by some exogenous force.

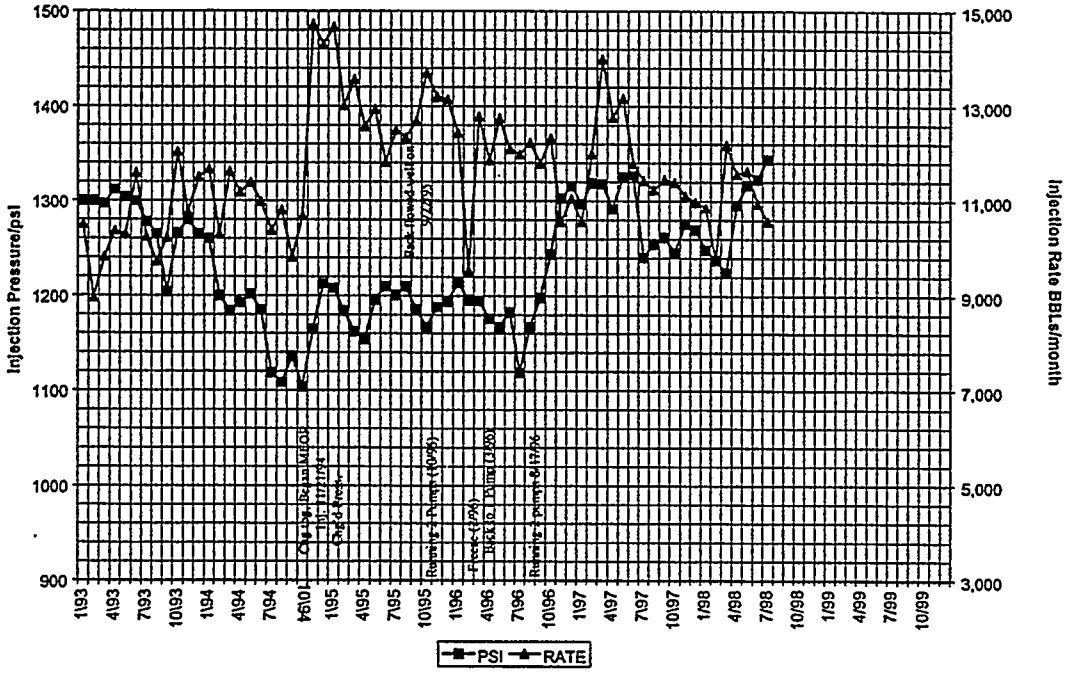


Figure A24. Injector Well 2-14 No. 1 (Test Pattern 1).

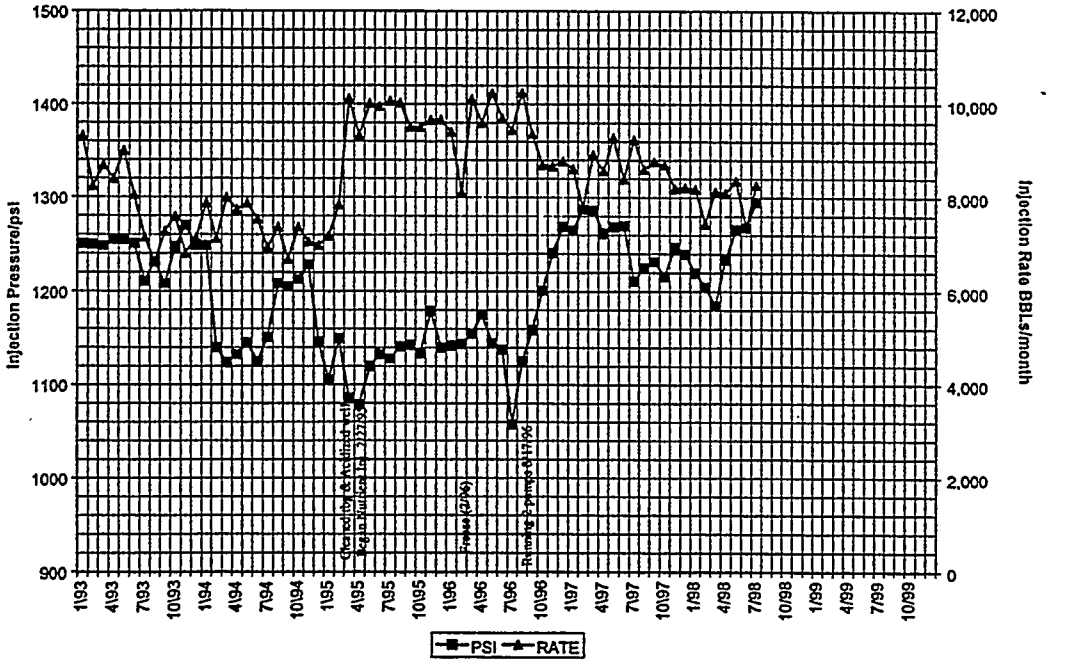


Figure A25. Injector Well 34-9 No. 2 (Test Pattern 2).

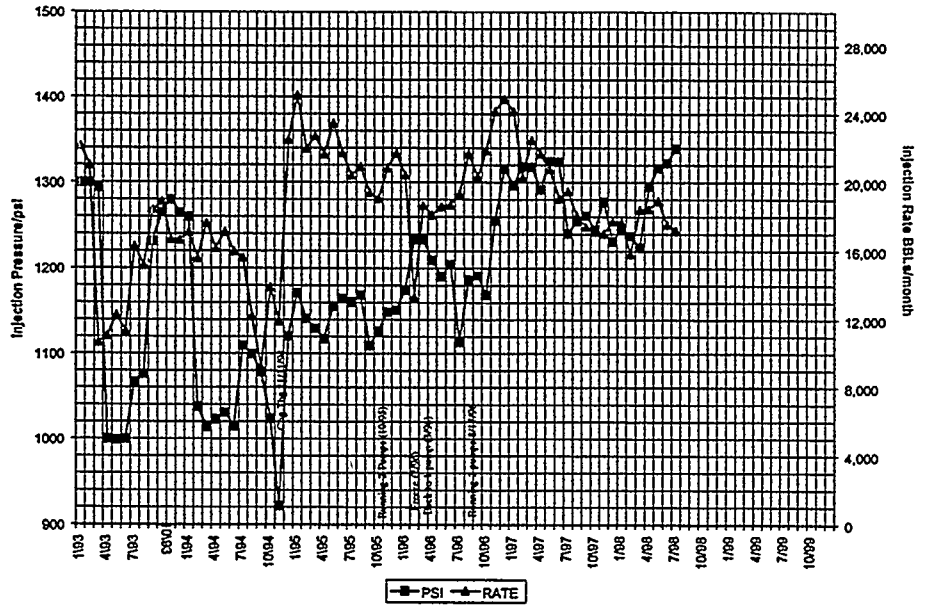


Figure A26. Injector Well 11-5 No. 1 (Test Pattern 3).

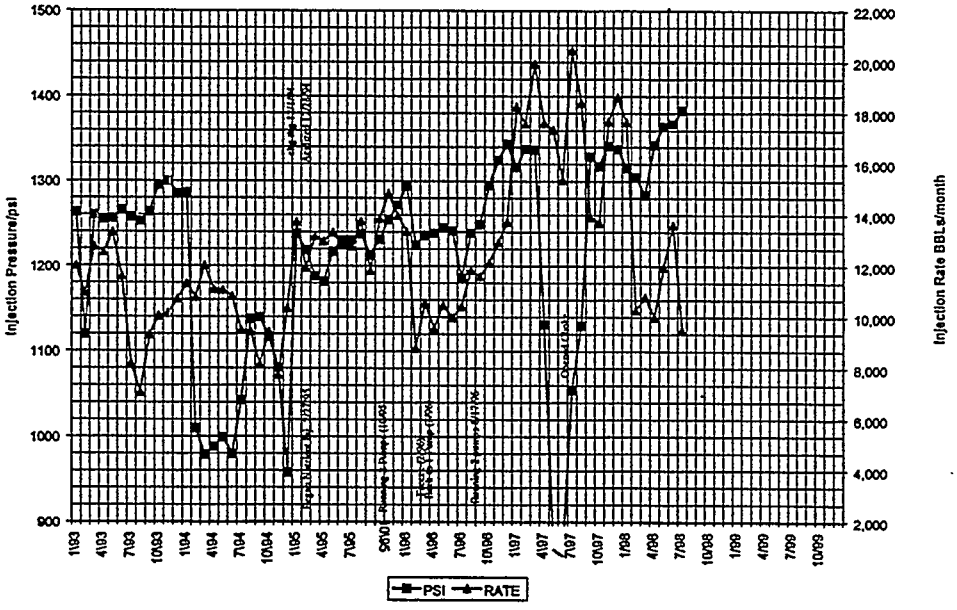


Figure A27. Injector Well 2-6 No. 1 (Test Pattern 4).

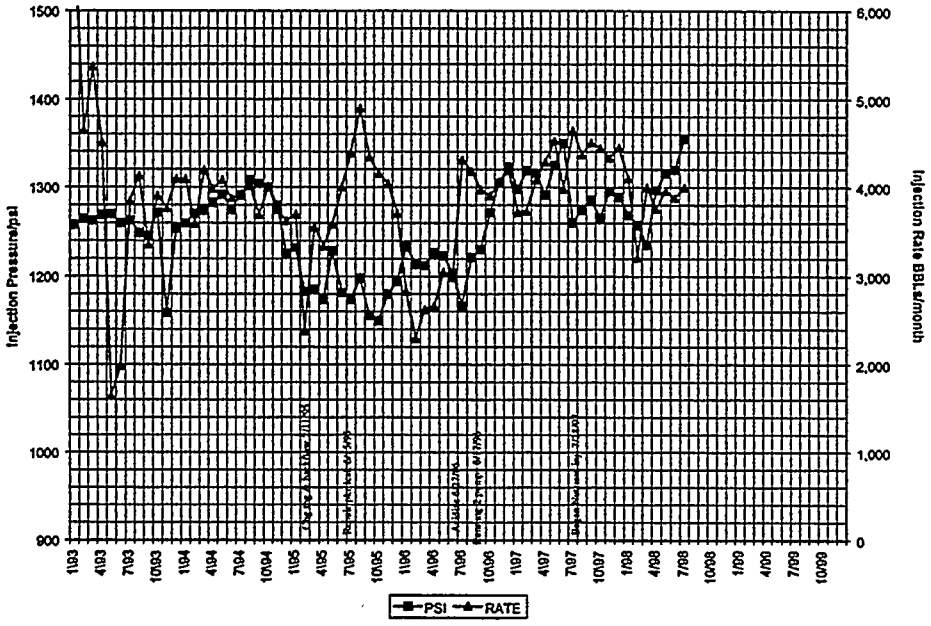


Figure A28. Injector Well 2-4 No. 1 (was injector for Control Pattern 1).

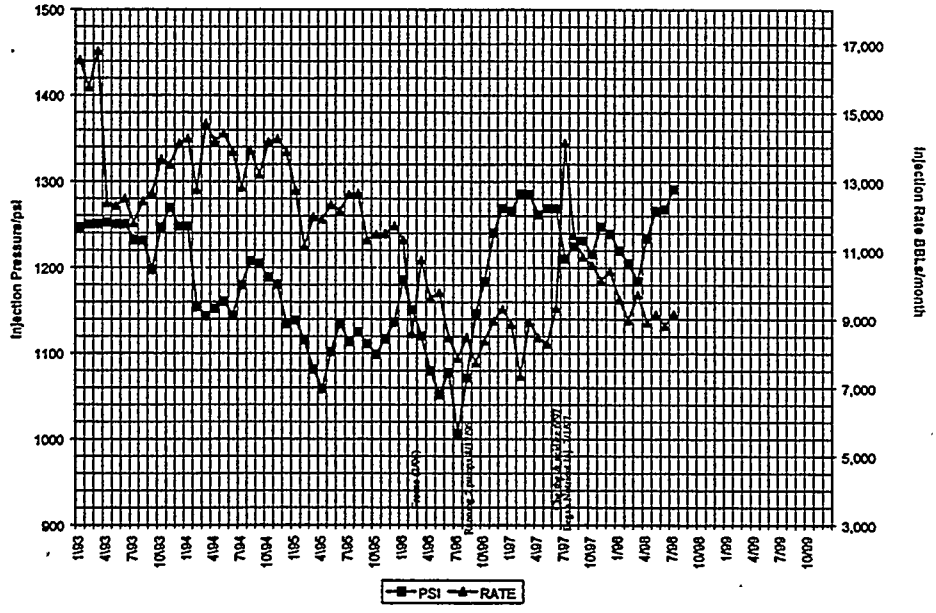


Figure A29. Injector Well 34-7 No. 1 (was injector for Control Pattern 2).

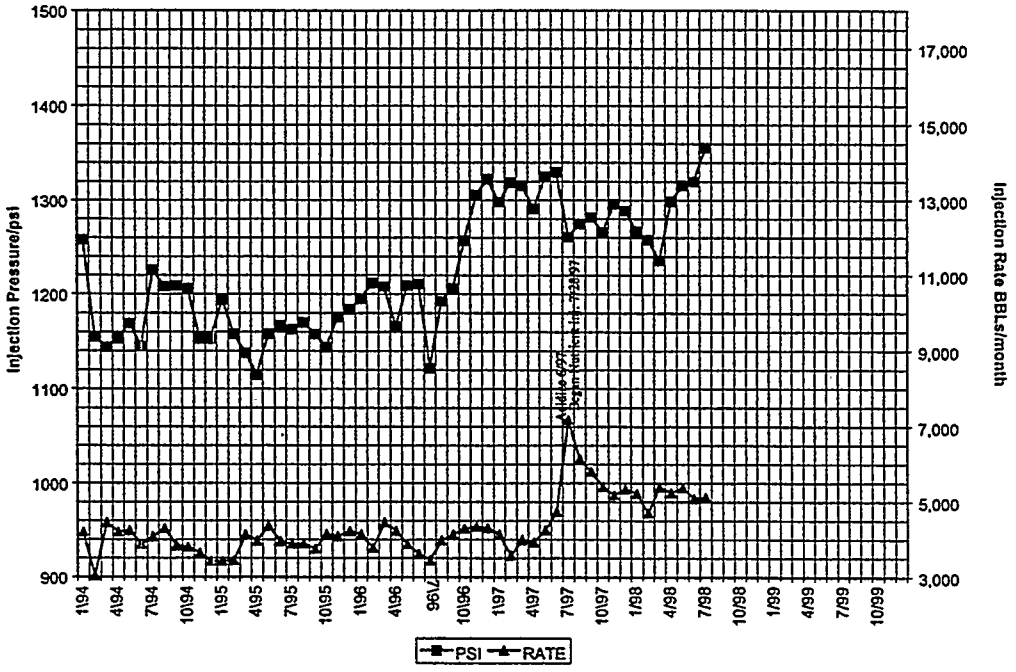


Figure A30. Injector Well 34-16 No. 1 (Not in Original Program).

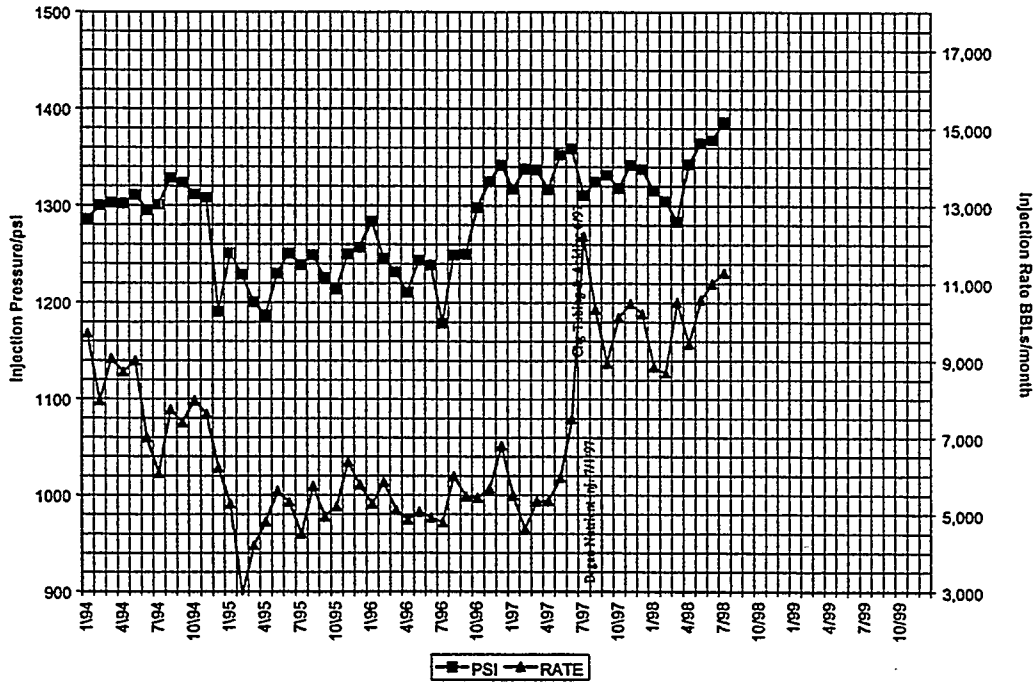


Figure A31. Injector Well 2-12 No. 1 (Not in Original Program).

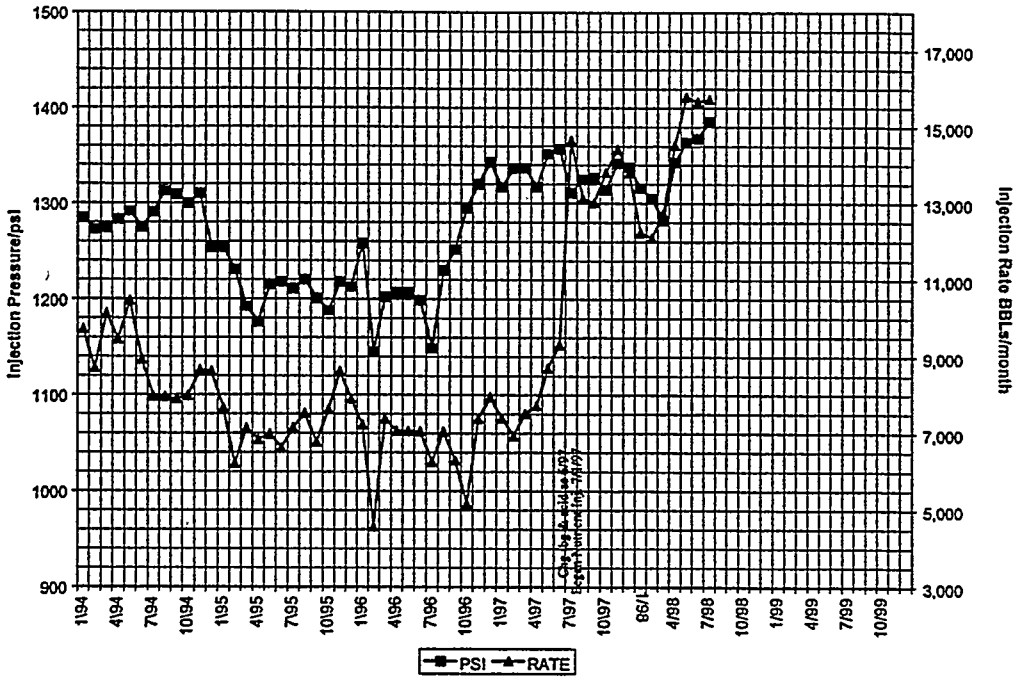


Figure A32. Injector Well 3-16 No. 1 (Not in Original Program).

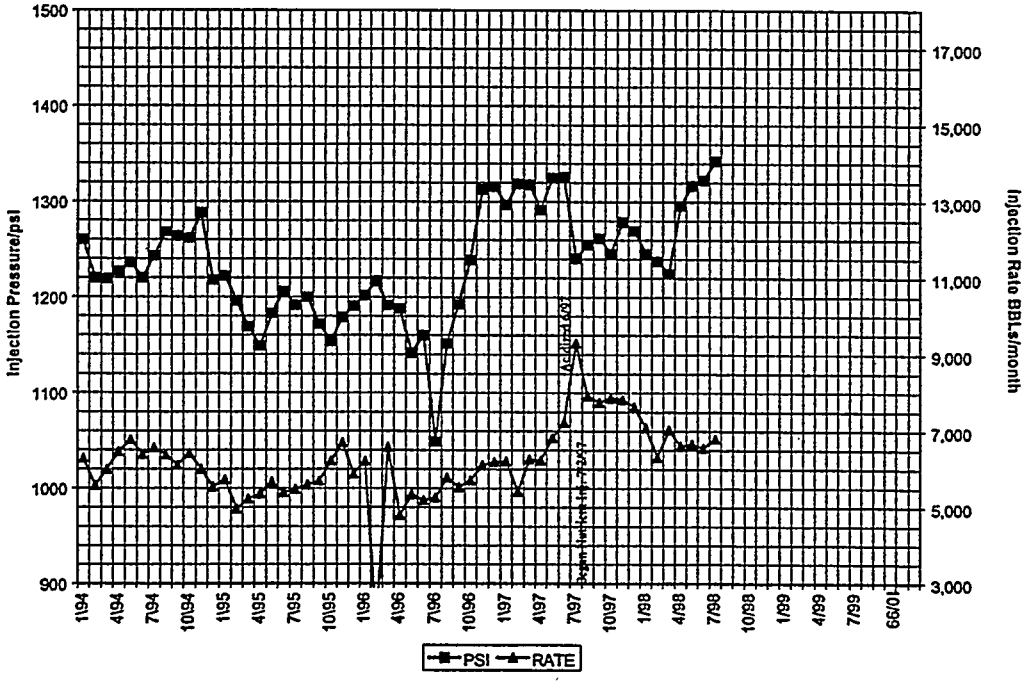


Figure A33. Injector Well 2-10 No. 2 (Not in Original Program).