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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

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

Hughes Eastern Corporation
Ridgeland, Mississippi

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

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ABSTRACT

This project is a field demonstration of the ability of *in-situ* indigenous microorganisms in the North Blowhorn Creek Oil Field to reduce the flow of injection water in the more permeable zones of the reservoir, thereby diverting flow to other areas thus increasing the efficiency of the waterflood. The project is divided into three phases -Planning and Analysis (9 months), Implementation (45 months), and Technology Transfer (12 months). This report covers the fifth year of work on the project.

During Phase I, cores were obtained from a newly drilled well and employed in laboratory core flood experiments to formulate the schedule and amounts of nutrient to be used in the field demonstration. The field demonstration involved injecting potassium nitrate, sodium dihydrogen phosphate, and in some cases molasses, into four injector wells (Test) and monitoring the performance of surrounding producer wells. For comparative purposes, the producer wells surrounding four untreated injector wells (Control) also were monitored.

Twenty-two months after the injection of nutrients into the reservoir began, three wells were drilled and cores taken therefrom were analyzed. Nitrate ions were found in cores from all three wells and cores from two of these wells also contained phosphate ions- thus demonstrating that the injected nutrients were being widely distributed in the reservoir. Microorganisms were found in cores from all three wells by cultural methods and by electron microscopy. In some sections of the cores, the number of microbes was large.

Oil production volumes and water:oil ratios (WOR) of produced fluids have shown clearly that the MEOR treatment being demonstrated in this project improved oil recovery. After 33 months, 7 of 15 producer wells in the test patterns responded positively to the injection of microbial nutrients into the reservoir, while all eight of the producer wells only in control patterns have continued their natural decline in oil production, although one well did have some improvement in oil production due to increased water injection into a nearby injector well. Two wells have been abandoned because of uneconomical production. In light of these positive findings and with DOE's approval, the scope of the field demonstration was expanded in July 1997 to include six new injector wells. Two of these wells were previously control injectors while the other four injectors were not included in the original program. Of interest was the performance of two wells in what was formerly a control pattern. Since the injector in this pattern (formerly control Pattern 2) began receiving nutrients, two of the wells in the pattern showed improved oil production. Overall, 12 of 19 producer wells that could have been influenced by the nutrient injections have shown a positive response.

Of special significance is the fact that over 10,970 m^3 (69,000 barrels) of incremental oil were recovered as a result of the MEOR treatment. Further, calculation showed that the economic life of the field will be extended. This finding is particularly impressive in view of the fact that only four of the twenty injector wells in the field were treated during the first 30 months of the demonstration (Phase II). By increasing the number of injector wells pumping microbial nutrients into the reservoir from four to ten, more oil was recovered and the economic life of the field will be extended even further. It should be emphasized that the above calculations do not take into account the oil being recovered from the five new wells that were drilled during the course of this project. Total incremental oil recovery of 94,600 m^3 (595 MBO) is expected and field life has been extended by 53 months.

EXECUTIVE SUMMARY

This project was designed to demonstrate that a microbially enhanced oil recovery process (MEOR), developed in part under DOE Contract No. DE-AC22-90BC14665, will increase oil recovery from fluvial dominated deltaic oil reservoirs. The process involves stimulating the *in-situ* indigenous microbial population in the reservoir to grow in the more permeable zones, thus diverting flow to other areas of the reservoir, thereby increasing the effectiveness of the waterflood. This five and a half year project is divided into three phases, Phase I, Planning and Analysis (9 months), Phase II, Implementation (45 months), and, Phase III Technology Transfer (12 months). Phase I was completed and reported in the first annual report. This fifth annual report covers the completion of Phase II and the first six months of Phase III.

Implementation (Phase II) involved injecting nutrients into four injector wells (Test) and comparing the performance of the surrounding producer wells to the performance of producers surrounding four untreated injector wells (Control). The addition of nutrients to the four test injector wells was begun on Nov. 21, 1994, Feb. 27, 1995, Jan. 16, 1995, and Feb. 27, 1995 for test patterns, 1, 2, 3, and 4, respectively. The nutrients being employed are potassium nitrate, sodium dihydrogen phosphate, and molasses.

In late 1996 three wells were drilled and completed and five sections of core from each well were analyzed for the presence of nitrate ions and orthophosphate ions that are being injected into the reservoir through the four test injectors. In one of the wells, nitrate ions were found in all five sections, but orthophosphate ions were found in only one section. In the second well, nitrate ions were found in four of the five sections, and orthophosphate was found in three sections. Three sections from the third well had nitrate ions in them but none had orthophosphate ions. The presence of microorganisms in cores from all three wells was demonstrated by observation with the electron microscope and by cultural methods. In some sections the number of microorganisms was large.

After 33 months, evaluation of oil production data and water:oil ratios (WOR) showed that seven of the fifteen producer wells in test patterns responded favorably to the MEOR treatment, while none of the eight producer wells only in control patterns showed an improvement in either oil production or WOR, although one well did have some improvement in production due to an increase in the amount of water injected into a nearby injector well. These positive findings prompted an expansion of the field demonstration (with DOE's approval) to include an additional six test injector wells. Two of these new test injectors were originally control injectors while the other four new injectors were not previously included in the field demonstration. The expansion began in July 1997 and all nutrient injections stopped in June 1998. After the expansion, twelve out of nineteen producers responded favorably to the MEOR treatment, over 10,970 m^{-3} (69,000 bbls) of incremental oil was recovered (exclusive of the five new wells), and the field life has been extended by 53 months.

INTRODUCTION

The use of microorganisms to enhance oil recovery (MEOR) was first proposed by Beckmann in 1926[1] but it was ZoBell who first actively researched the concept[2-5]. Some MEOR methods rely on *in-situ* indigenous microbial populations while other methods require injection of microbial cultures into the formation. In some MEOR methods, it is the by-products of microbial activity that enhance the oil recovery but other methods rely on the increase in microbial mass to achieve the desired result.

This five and a half year project was designed to demonstrate that the microflora indigenous to petroleum reservoirs can be stimulated to grow in the more permeable zones of the reservoir thereby diverting flow to other areas and thus increase the effectiveness of the waterflood. The concepts involved in this project were developed in part as a result of work performed under DOE Contract No DE-AC22-90BC146645. Work on this project is divided into three phases of nine months, forty-five months, and twelve months, respectively. This Fifth Annual Report will describe the work completed during the last six months of Phase II and the first six months of Phase III.

DISCUSSION

1. OBJECTIVE AND OVERALL PLAN OF WORK

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

One expected outcome of this new technology will be a prolongation of economical waterflooding operations, i.e. economical oil recovery should continue for much longer periods in areas of the reservoir subjected to this selective plugging technique.

2. DESCRIPTION OF OIL RESERVOIR FOR FIELD TRIAL

The North Blowhorn Creek Oil Unit (NBCU) is located in northwest Alabama about 125 kilometers (seventy-five miles) west of Birmingham, AL (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 meters (2300 feet). The field was discovered in 1979 and initially developed on $3.24 \times 10^5 m^2$ (80 acre) spacing. The field was unitized into a reservoir-wide unit in 1983 and in-fill drilled to $1.62 \times 10^5 m^2$ (40 acre) spacing. Waterflooding of the reservoir began in 1983. The initial oil in place in the reservoir was about 2.5 million m^3 (16 million barrels), of which 874,430 m^3 of oil (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 480 m^3/d of oil (3000 BOPD) in 1985 and has since steadily declined. At the start of the project, there were 20 injection wells and 33 producing wells producing about 46 m^3/d of oil (290 BOPD), 1700 m^3/d of gas (60 MCFD), and 800 M^3/d of water (3900 BWPD). The water injection rate was about 650 m^3/d of water (4150 BWPD). About 1.6 m^3 of oil (10 MMBO) were left unrecovered at the outset of this project.

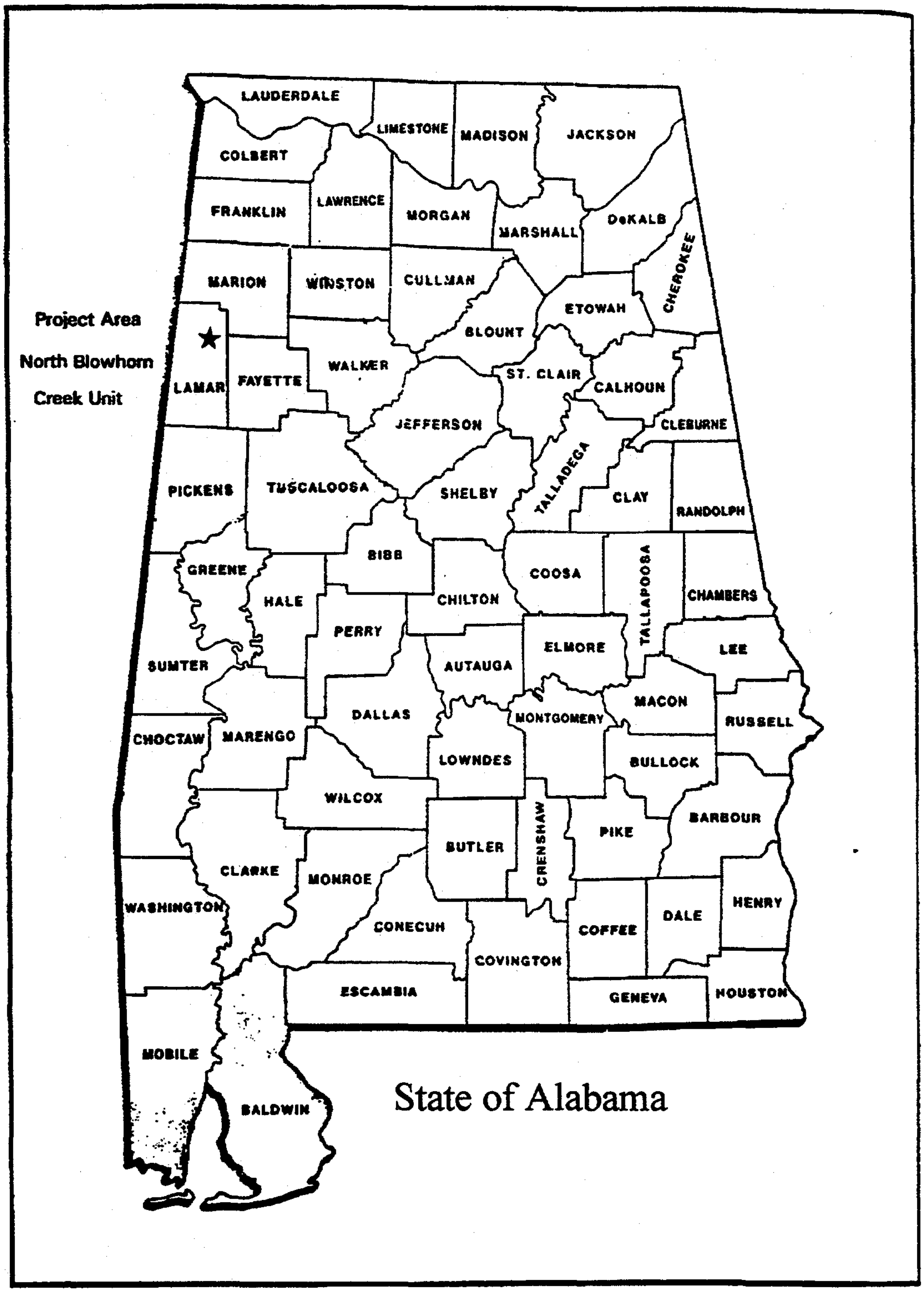

Figure 1. Project area geographical locator map.

3. PHASE I. PLANNING AND ANALYSIS

Phase I began with the drilling of two wells to obtain live cores for laboratory studies and to obtain the production data which would indicate how well the reservoir was being swept by the existing waterflood. Analysis of the cores proved that viable microorganisms were present and since sulfate-reducing bacteria (SRB) were not present, it was concluded that the area in which the wells were drilled probably had not been impacted by the waterflooding since SRB were prevalent in fluids from other wells in the field. Laboratory waterflooding tests using live cores clearly demonstrated that the *in-situ* microflora were stimulated to grow and retarded fluid flow through the core. Control cores injected with only simulated production water increased in flow rate as expected while the test cores injected with water containing potassium nitrate and sodium dihydrogen phosphate had reduced flow rates. Based on these laboratory results, the feeding regime shown in Table 1 was formulated.

Table 1. Feed and Feeding Regime from November 1994 to April 1996

NUTRIENTS	PATTERNS			
	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 Friday	0.034% (w/v) Fridays	same as 1	same as 2
MOLASSES		0.1% (v/v) Wednesdays	same as 1	same as 2

For the field demonstration, four injector wells were selected for nutrient additions and the surrounding producer wells were monitored. Results obtained in these tests were compared to historical data for the wells and to data obtained from four additional injectors and their surrounding producers which are serving as controls in order to evaluate the success of the project.

a. Test Patterns for Field Demonstration

Test Pattern 1

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*

Control Pattern 1

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

Test Pattern 2

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*

Control Pattern 2

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

Test Pattern 3

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*

Control Pattern 3

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*

Test Pattern 4

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*

Control Pattern 4

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.

b. Tracer Study

A tritium tracer survey was initiated in Test Pattern 1 in April, 1994. Two curies of tritium were injected into well 2-14 No. 1 and water samples from the four offset producers were monitored for tracer breakthrough. The tracer was first detected in NBCU 2-13 No. 1 on October 12, 1994 and continued to be detectable through October 1996. Tracer was first detected in the NBCU 11-3 No. 1 on October 18, 1995 and continued to be detectable through October 1996. No other wells produced detectable amounts of the tracer.

c. Nutrient Injection Facilities

From the laboratory results of the core flood experiments it was determined that each injection facility needed the ability to mix and pump 100-300 gallons of water containing 50-400 lbs of chemicals per day at a pressure of 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. The nutrients were packaged as dry crystals in 50 to 100 lb bags, so the ability to mix the chemicals and know that all went into solution was required. The skid had to be designed for simple maintenance and operation by the field lease pumpers. A small storage area to keep unused chemicals dry also was required.

Based upon these requirements, a facility was constructed of an oil field type skid with a metal roof and storage cabinet at one end. A mixing hopper was fabricated to make use of the 1200 psi waterflood water as a mixing jet for the dry sack chemicals. The mixture is stored in a 300 gallon plastic tank which allows direct observation and sampling of the solution. The tank contains an electric stirrer which is generally run for a couple of hours after each batch of chemical is mixed to ensure that all of the chemicals dissolve. The mixture is pumped downhole by a large air powered chemical pump which has a variable speed, but precise displacement at any given speed. Subsequent designs have switched to a small triplex pump driven by a DC electric motor with variable 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 comes directly from the waterflood line near the wellhead and the discharge line ties into the well just upstream of the wellhead assembly. Four skids were initially fabricated, one for each of the test injector wells.

4. PHASE II. IMPLEMENTATION

a. Field Demonstration

The injection of nutrients into the first of four injector wells began November 21, 1994. The addition of nutrients into three additional injector wells began in January and February, 1995. Of the four injectors in the test patterns, two received potassium nitrate and sodium dihydrogen phosphate while the other two received 0.1% molasses in addition, as shown in Table 1.

b. Changes in 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 feeding regime as shown in Table 2.

Table 2. Feed and Feeding Regime from April 1996 - June 1997.

NUTRIENTS	PATTERNS			
	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

c. Expansion of the Field Demonstration

It became apparent after 30 months of monitoring, that the producer wells (8), not influenced by the injection of nutrients into nearby injector wells, continued their historic natural decline in oil production rate. Contrariwise, nearly half of the wells (15) in areas being waterflooded with microbial nutrients exhibited improved oil production rates. As a result of these findings, it was requested (and approved by DOE) to expand nutrient injection by injecting nutrients into two control injectors [wells 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 original 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 on Figure 2.

d. Final Feeding Regime

After a careful evaluation of the field results, it was decided to modify the feeding regime for a second time. The feeding regime employed from July 1997 to completion of the field demonstration in June 1998 is shown in Table 3.

e. Drilling of Three Additional Wells

Three wells were drilled into the Carter reservoir sand during the Fall of 1996. The purpose of the three wells was to help evaluate the nutrient induced growth of in-situ microorganisms by analysis of recovered core samples and produced fluids. The locations of the wells are shown in Figure 2.

The first well drilled was the NBCU 2-5 No. 2 which started drilling on October 11, 1996 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 analysis indicates that, as a general rule, the lower permeability rock retains a higher oil saturation while the high permeability rock is 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. Well 2-5 No. 2 was placed on rod pump in January 1997 and in February produced 28 m^3 oil (177 BO), 0.18 m^3 gas (63 MCF), and 864 m^3 water (5433 BW). Production has steadily declined to the point where the well presently produces about 0.4 m^3 oil/day (2.7 BOPD) and 6.9 m^3 water/day (43 BWPD).

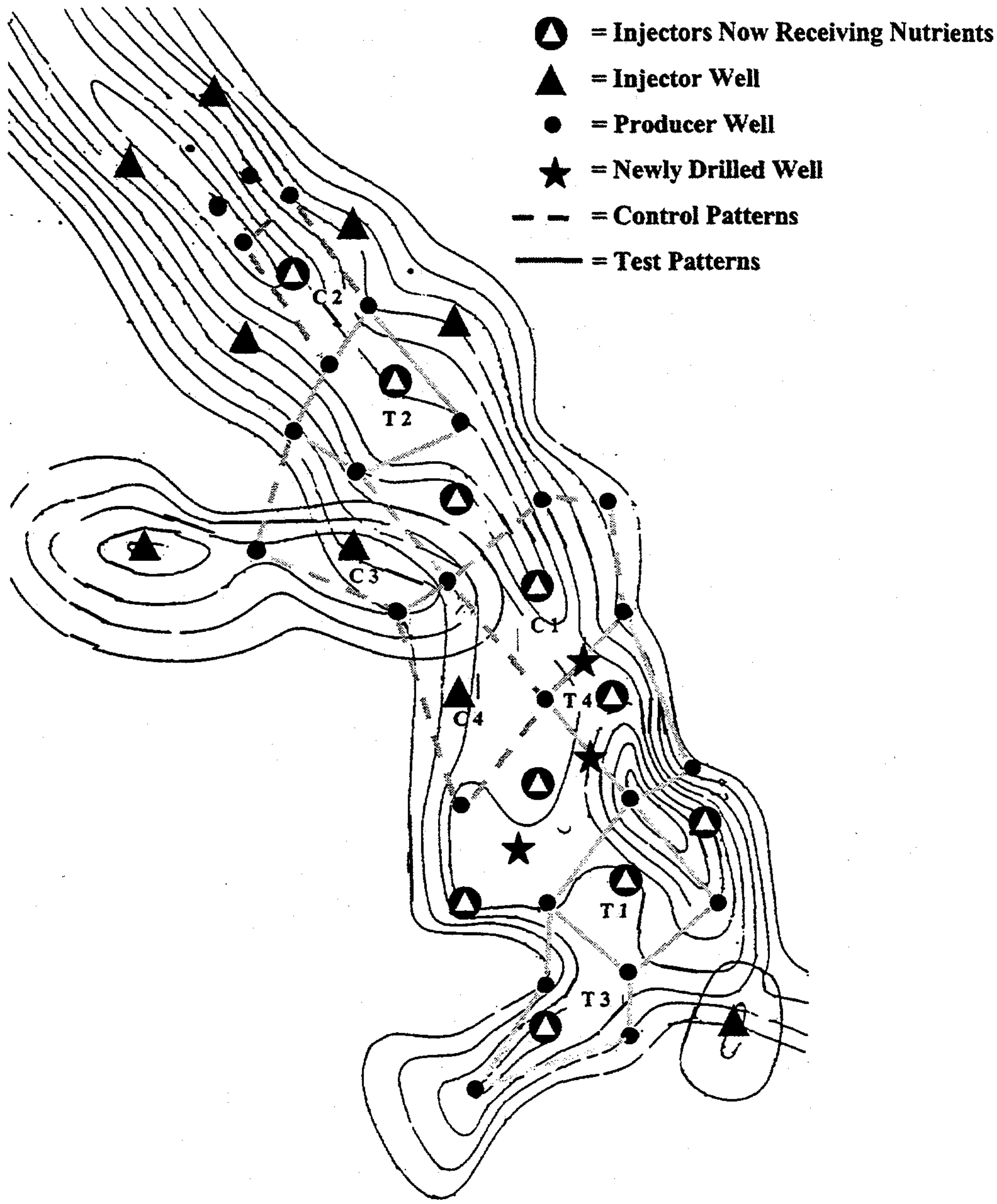

Figure 2. Location of the ten injector wells that received nutrients.

Table 3. Feed and Feeding Regime for All Ten Injector Wells Since July 1997.

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		0.02 P
34-9 No. 2	0.11 N		0.18 M		0.05 P
3-16 No. 1		0.19 N 0.05 P		0.32M	
34-7 No. 1		0.17 N 0.04 P		0.21 M	
2-10 No. 2		0.12N 0.02 P		0.19 M	
11-5 No. 1	0.15 N		0.29 M		0.04 P
2-12 No. 1		0.26 N 0.07 P		0.43 M	
2-14 No. 1	0.08 N		0.47 M		0.02 P

All numbers are percentage figures
N = percent potassium nitrate (w/v),
P = percent sodium dihydrogen phosphate (w/v),
M = percent molasses (v/v).

The second well drilled was the NBCU 2-13 No. 2 which started drilling on October 22, 1996 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 (2180 and 2205 ft) and 9.7 m (32 ft) of core were recovered. The core analysis indicates 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 has lower oil saturation than the lower permeability rock which is 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 initially swabbed 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 in January 1997. Current production is 1.3 m^3 oil/day (8 BOPD with 3.4 m^3 water/day (22 BWPD).

The third well drilled was the NBCU 2-11 No. 3 which started drilling on November 6, 1996 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 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 was placed on production flowing at a rate of 2.9 m^3 oil/day (18 BOPD) and 34.0 m^3 water/day (214 BWPD), but the rate quickly declined and rod pumping equipment was installed in April 1997. The well initially produced about 1.0 m^3 oil/day (6 BOPD) and 64.0 m^3 water/day (400 BWPD) on pump, but the oil production continued to decline to about 0.3 m^3 oil/day (2 BOPD) with 40.0 m^3 water/day (250 BWPD) and the well was shut-in during August 1997. The well was produced again in November and December, but there was no improvement in production. This well yielded the poorest production as a result of its close proximity to the 2-6 No. 1 nutrient injector. The well's apparent very direct hydraulic communication with the 2-6 No. 1 resulted in water withdrawal from the pattern of sufficient magnitude to significantly adversely affect other wells in that pattern (2-5 No. 1, 2-11 No. 1, and 2-11 No. 2). The well was plugged and abandoned in July 1998.

f. Analyses of Cores from the Three New Wells

(1) Chemical

The presence or absence of nitrate ions and orthophosphate ions in five sections of core from each of the three newly drilled wells was determined. 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 demonstrate that the nutrients are being widely distributed in the oil-bearing formation.

(2) Microbiological

Microorganisms were 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 3 were observed in a number of samples from all three wells and in some cases (see Figures 4, 5, and 6) large clusters of cells were observed indicating that the added nutrients had the desired effect of promoting microbial growth in the reservoir.

(3) Geological Characterization of Core Samples

The core samples appear 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.

(4) Petrophysical Properties of Core Samples

The petrophysical properties of collected cores from the three wells drilled in Phase II are given in Table 4. In this Table the lowest, the highest, and a median range of values is presented to show the intensity of heterogeneity of the reservoir formation.

Table 4: Petrophysical Properties of Cores from Three Newly Drilled Wells.

WELL NAME	DEPTH m	DEPTH ft	POROSITY (%)	PERMEABILITY (md)	FLUID SATURATION % Oil	FLUID SATURATION % H_2O	GRAIN DENSITY (g/cc)
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

g. Analyses of Injection and Production Fluids

Fluids from both injector wells and producer wells in all patterns, were collected monthly in one and a half 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, vicosity, and interfacial tension (IFT). Additionally, the water samples were analyzed for surface tension (ST), pH, microbial content, and several inorganic ions. Furthermore, production rates of produced fluids (oil, gas, and water) from the producer wells in all patterns were measured weekly by the field lease operator.

(1) Petrophysical analyses

The following characteristics of produced fluids from selected wells have been measured and representative values given in Table 5.

- **Aliphatic profile**

  Gas chromatographic analyses were conducted to determine the aliphatic profile of oil from producer wells in all patterns. From these data evidence of oil from previously unswept areas of the reservoir has been found in the oil from some producers. This finding helps confirm that microbial growth in the reservoir is indeed altering the sweep pattern in the reservoir.

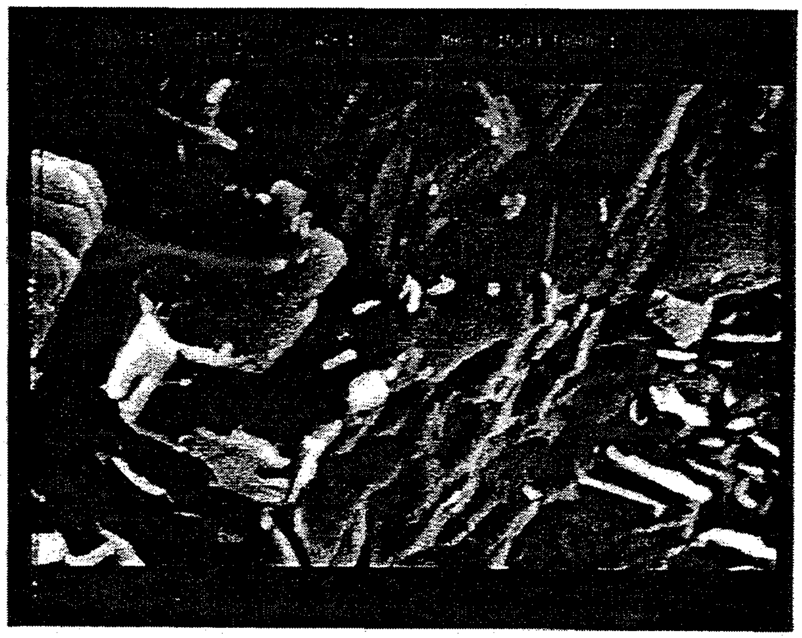

Figure 3. Electron micrograph of a sample of core from well 2-13 No.2, section 6. (Note the scattered microbial cells.)

Figure 4. Electron micrograph of a sample of core from well 2-11 No.3, section 3. (Note the large number of microbial cells.)

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

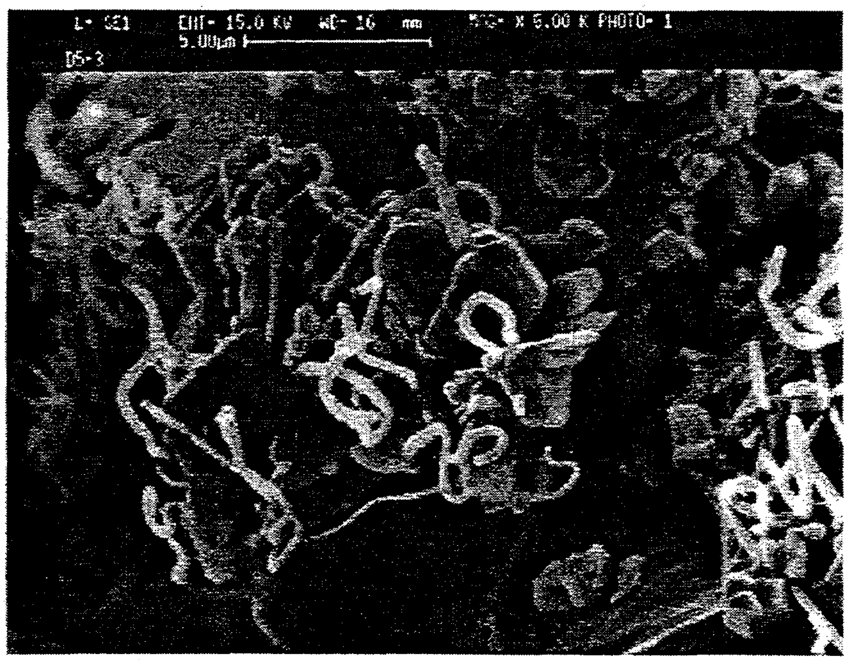

Figure 6. Electron micrograph of a sample of core from well 2-11 No.3, section 3. (Note the large number of microbial cells.)

Table 5. 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

Control 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

Control 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

Table 5. (Continued)

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	2.96-29.8	62.1-69.7	27.75-23.56	7.3-7.5
Trend	upward	upward	steady	steady	steady

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

- **API gravity**

  It is expected that the API gravity from producers influenced by altered waterflood sweep patterns will increase as new oil (lighter oil) is swept into the producing wells. Generally speaking, as the waterflood continues, oil becomes heavier. If oil from unswept areas is entering the production stream, the API gravity should increase if in sufficient quantity. Information on gravity variation therefore would be supportive evidence that the production and quality of new oil is due to microbial selective plugging. The gravity of new oil is not expected to increase to more than original oil which was around 33-35^0 API (See Table 5).

- **Viscosity**

  It is expected that the viscosity of the crude oil will decrease as new oil (lighter oil) is swept into producing wells. Generally speaking, decrease in viscosity would be supportive of waterflood modification due to microbial growth. Lighter oil has lower viscosity. The viscosity of new oil, however, is not expected to be lower than the original oil which was around 1.5-2 cp (See Table 5).

- **Interfacial tension, IFT**

  Due to the production of certain surfactants by some microbial populations, there may be a reduction of interfacial tension between oil and water phases and/or between water and oil and the sand surface. Monitoring IFT in a producing oil-water system may lead to evidence of microbial activities in the reservoir (See Table 5).

- **Surface tension, ST**

  Monitoring surface tension in a producing oil and water system gives some indication of changes in the nature of produced oil when comparing it to oil from control well production data and/or historical data from the same well (See Table 5).

- **pH**

  Monitoring the acidity of produced water and comparing it to water from control wells or historical data are designed to detect drastic or systematic changes in the fluid. In particular, the production of acid and/or other corrosive materials would be detrimental to the quality of oil or production facilities and eventually the environment (See Table 5).

(2) Microbiological Findings

The microbiological analyses of production fluids has not shown 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 and consequently, numbers of microbes in production fluid do not necessarily reflect the size of the population in the reservoir.

(3) Inorganic Ion Findings

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 injections but were present initially. 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 of the cores 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 these 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.

(4) Gas Composition Findings

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 gas chromatography 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. The data suggest that the increase in gas production was due to gases from previously unswept areas of the reservoir.

h. Performance of Production Wells.

The injection of nutrients into the formation was initiated in November of 1994 and was completed in June 1998. The starting nutrient injection date for test pattern 1 was Nov. 21, 1994; test pattern 2 was Feb. 27, 1995; test pattern 3 was Jan. 16, 1995, and test pattern 4 was Feb. 27, 1995. In June 1997 following a request from Hughes Eastern and approval by DOE, two control injectors were changed to test injectors and four additional injectors (not previously included in this study) were made into test injectors.

In evaluating performance, both oil production rate and water:oil ratio (WOR) were considered. The impact of the MEOR process was characterized as positive if the oil production rate increased, held steady, or there was a noticeable decrease in the rate of decline and the WOR decreased, held steady, or there was a reduction in the rate of increase. Overall, the performance of the test wells was characterized as Positive, Inconclusive, or None, while the performance of the control wells was characterized as Positive, Natural Decline, or Abandoned, except in one case where other comments were made (see Table 6 and 7). The performance of producing wells in all patterns is given in Figures A1-A21 in the Appendix. It should be pointed out that there was a drop in production in February 1996 due to a severe freeze which shut down field operations for about a week.

i. **Performance of Injector Wells.**

(1). 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 A22).

(2). 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 A23).

(3). 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 A24).

(4). 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 the 2-11 No. 3. Injection pressure increased and the injection volume decreased over the last year (see Figure A25).

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

Injection volume declined as injection pressure increased (see Figure A26).

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

Injection volume declined as injection pressure increased (see Figure A27).

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

Injection pressure increased, more water intake. No indication of plugging (see Figure A28).

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

Injection pressure increased, more water intake. No indication of plugging (see Figure A29).

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

Injection pressure increased, more water intake. No indication of plugging (see Figure A30).

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

Injection pressure increased, more water intake. No indication of plugging (see Figure A31).

Table 6. Performance of Wells That Were Originally in Test Patterns.

Well No.	Pattern	Response to MEOR	Remarks
2-11 No. 1	1 and 4	Positive	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. This well is a shared well with Test Pattern 4. 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.
2-15 No. 1	1	Inconclusive	Production from this well has been erratic.
11-3 No. 1	1 and 3	Positive	Oil production increased from Jan. 1997 to Apr. 1998 and has remained steady since that time. WOR has generally remained steady.
2-13 No. 1	1 and 3	Positive	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.
34-7 No. 2	2	Positive	During the last 2 years, there has been an increase in oil production and the WOR declined slightly. This well is shared with Control Pattern 2.
34-16 No. 2	2	Inconclusive	Oil production demonstrated a natural decline until July 1997 after which time the production decline decreased somewhat.
34-15 No. 1	2	Positive	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. This well is shared with Control Pattern 3.
34-15 No. 2	2	Positive	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. This well is shared with Control Pattern 3.

Table 6. Continued

34-10 No. 1	2	Positive	Oil production declined until Sep. 1997, at which time it increased and the WOR declined. This well is shared with Control Pattern 2.
10-8 No. 1	3	None	This well had mechanical problems. While oil production did not show a positive response, 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. WOR held steady.
11-6 No. 1	3	Positive	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.
11-4 No. 1	3	None	This well continued its natural decline. WOR slightly increased.
2-11 No. 2	4	Positive	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. WOR remained steady.
2-3 No. 1	4	Positive	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 benefitted from nutrient injection in Control Pattern 1.
2-5 No. 1	4	None	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. This well is a shared well with Control Patterns 1 and 4.

Table 7. Performance of Wells That Were Originally in Control Patterns.

Well No.	Pattern	Response to MEOR	Remarks
35-13 No.1	1	Natural Decline	Oil production rate continuously decreased and WOR slightly increased.
35-14 No. 1	1	Abandoned	Due to uneconomical production rate
3-1 No. 1	1,3, and 4	Natural Decline	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).
34-2 No.1	2	Positive	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 declined.
34-6 No. 1	2	Abandoned	Due to uneconomical production rate.
3-1 No. 2	3 and 4	Increased oil not due to MEOR	The positive response in oil production was due to an increase in water injection, not MEOR. WOR fluctuated due to refracturing of the well.
3-3 No. 1	3	Natural decline	Oil production has remained essentially steady since May 1995 due to increased water injection into Control Injection well 3-2 No. 1. WOR increased.
3-9 No. 1	4	Positive	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.

j. Overall Performance of Field Demonstration

In evaluating the overall performance of the MEOR 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. Fluid production for the field from Jan. 1992 thru Aug. 1998 is given in Figure 7. During the period May 1994 thru Dec. 1998, total oil production was 74,700 m^3 (470 MBO). Based 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 25,600 m^3 (161 MBO) of incremental oil produced, 14,563 m^3 (92 MBO) were from production of the five new wells, thus 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 thru Apr.1994 indicate that the field would reach its economic limit of 238 m^3 (1500 bbls) of oil per month in 63 months (from 1/1/98 assuming oil prices recover to over $15/bbl). Based on the current oil production rate, the remaining economic life of the field is 116 months. Thus, economic production would last 53 months longer, exclusive of any additional positive response from continued nutrient injection into the ten test injector wells. The expected total project incremental oil recovery without any additional positive MEOR response is projected to be 94,600 m^3 (595 MBO).

5. PHASE III. TECHNOLOGY TRANSFER

The last year of this project is devoted to analyzing data and to technology transfer. It is realized of course, that technology transfer is an on-going process. 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

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

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, 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 "Core" in Nov. 1998. [Core 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.

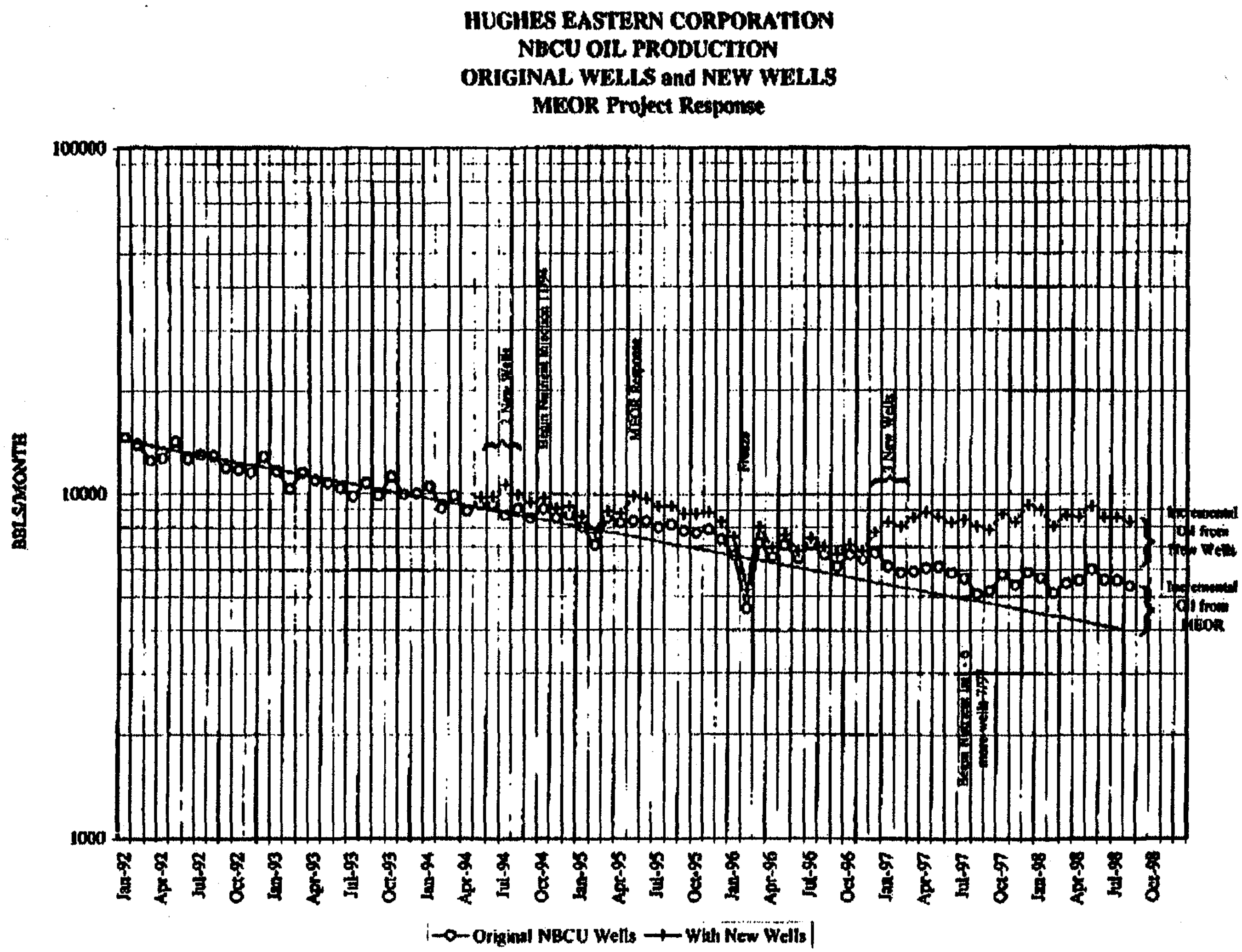

Figure 7. Total production from North Blowhorn Creek Oil Field.

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.

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

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.

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

There also have been 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 Tidlands Oil Co. when in Long Beach, CA. Also, material on our findings were 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.

Arrangements are being made to make a presentation to the DOE, NPTO 1999 Oil and Gas Conf. to be held in Dallas June 28-30, 1999.

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2. ZoBell, C.E., 1943. Bacteria as a geological agent, with particular reference to petroleum. Petrol. World, Vol. 40, pp. 30-43.

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5. ZoBell, C.E., 1953. Recovery of Hydrocarbons. U.S. Pat. No. 2,641,566.

6. American Public Health Assoc., American Water Works Assoc., and Water Environment Federation. 1992. Standard Methods for the Examination of Water and Wastewater. APHA, AWWA. WAF, Eighteenth ed.

APPENDIX

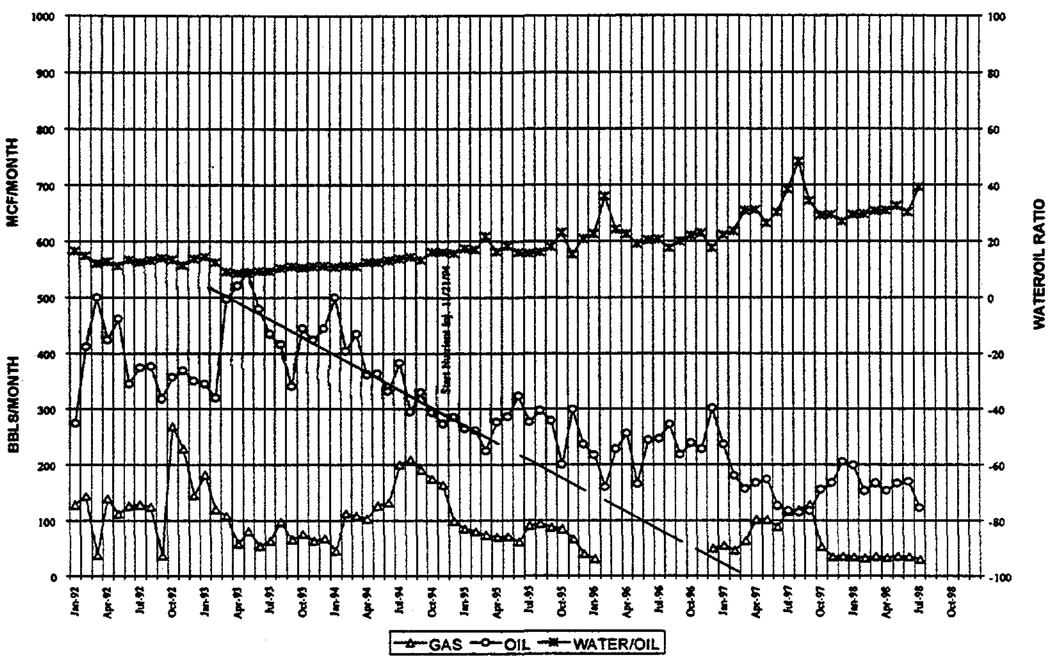

Figure A1. Performance of well 2-11 No.1 (TP 1, TP 4, and 2-10 No. 2 Nutrient Injectors).

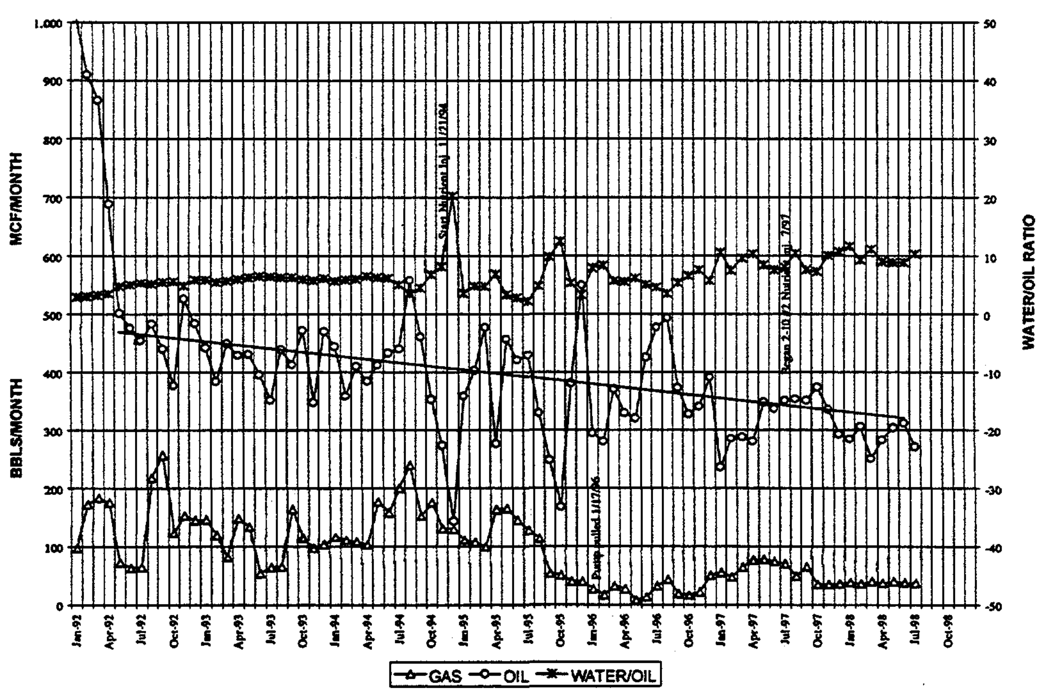

Figure A2. Performance of well 2-15 No.1 (TP 1 and 2-10 No. 2 Nutrient Injectors).

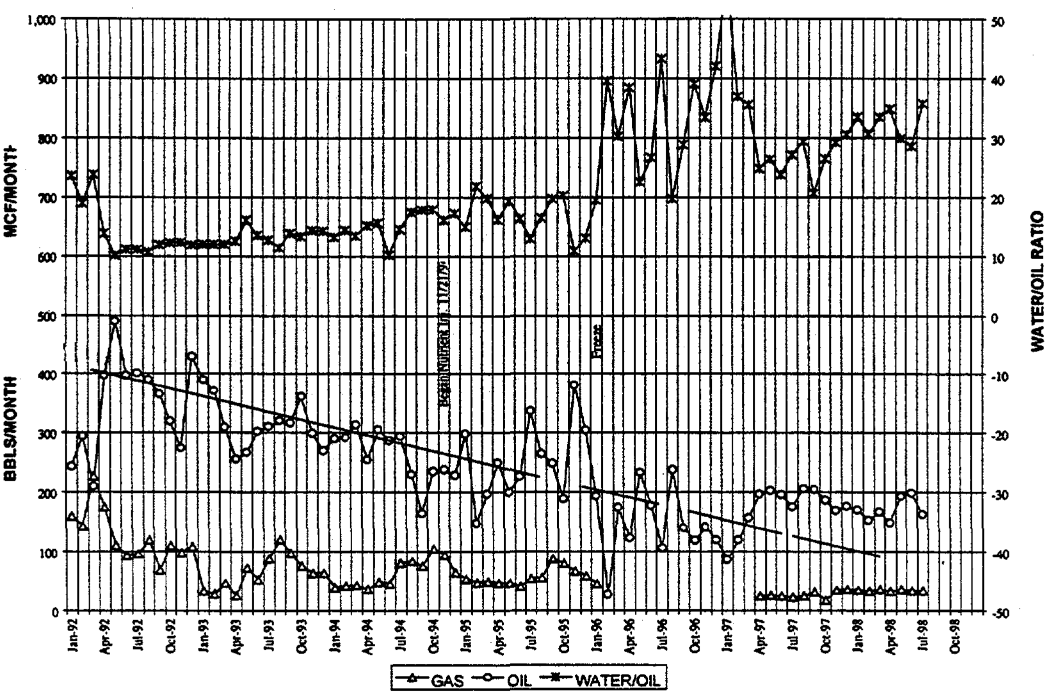

Figure A3. Performance of well 11-3 No.1 (TP 1 and TP 3).

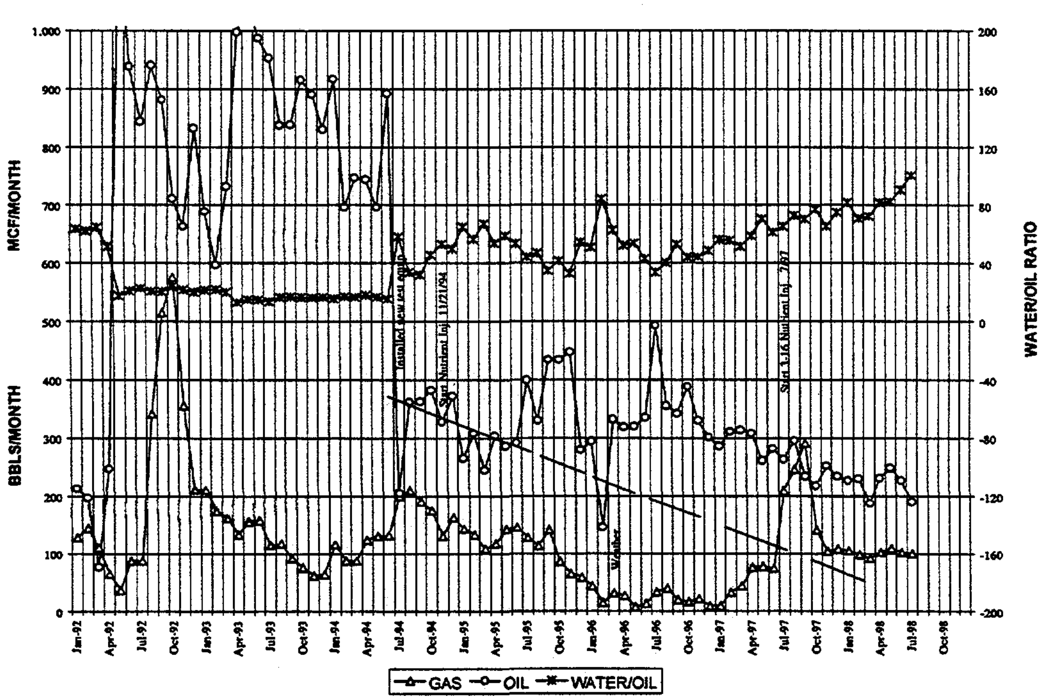

Figure A4. Performance of well 2-13 No.1 (TP 1 and 3-16 No. 1 Nutrient Injectors).

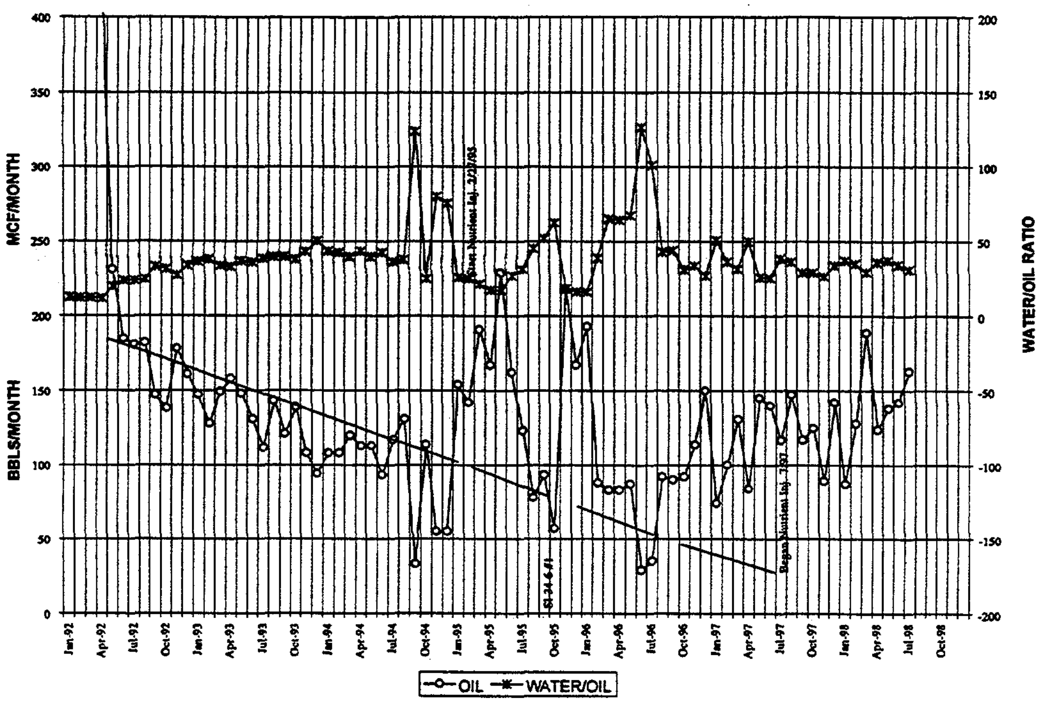

Figure A5. Performance of well 34-7 No.2 (TP 2 and 34-7 No. 1 Injectors).

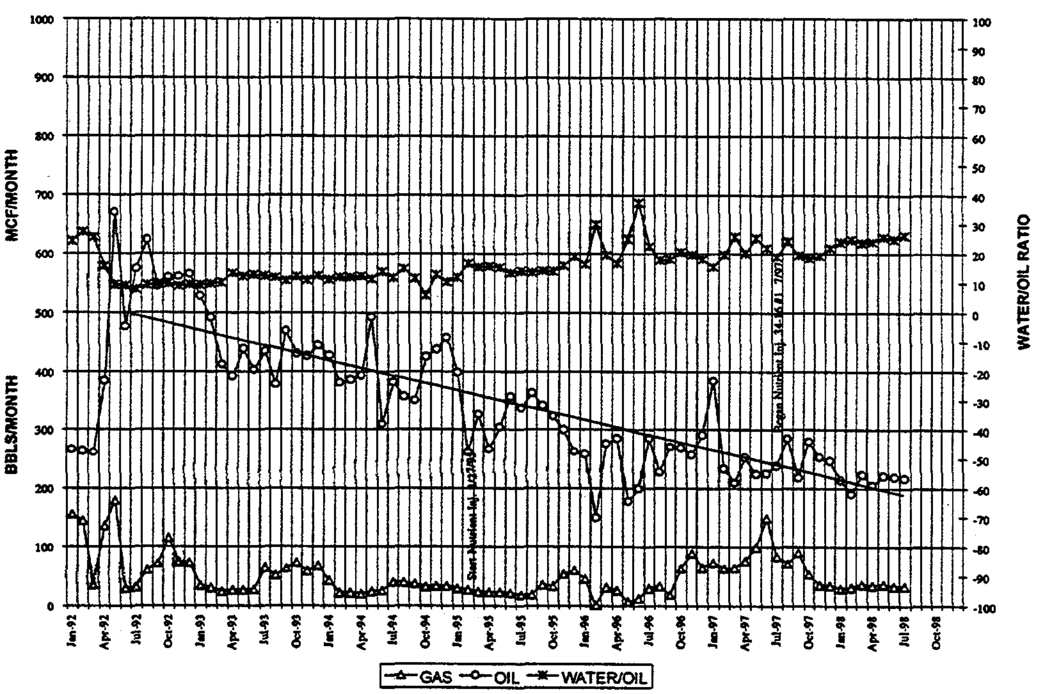

Figure A6. Performance of well 34-16 No.2 (TP 2 and 34-16 No. 1).

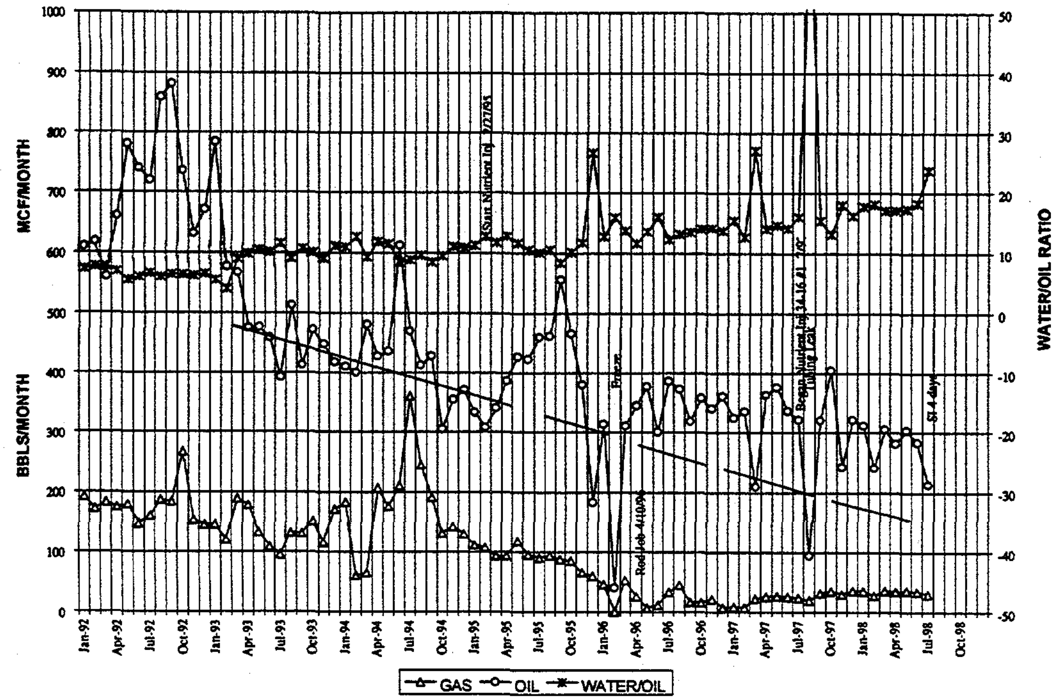

Figure A7. Performance of well 34-15 No.1 (TP 2 and 34-16 No. 1 Nutrient Injectors).

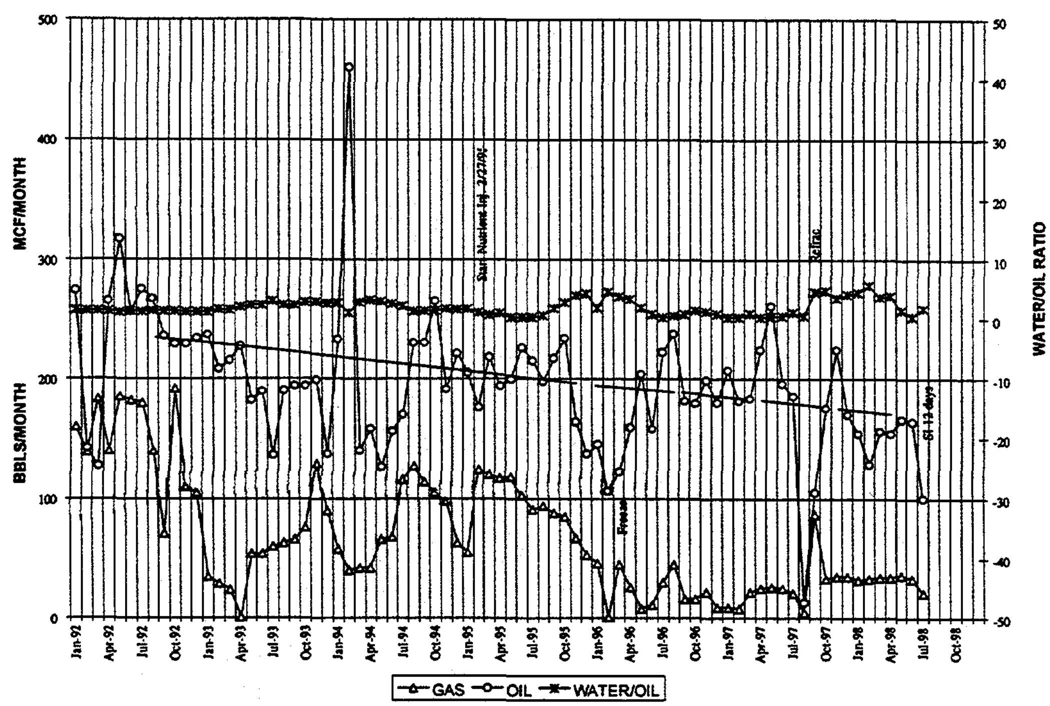

Figure A8. Performance of well 34-15 No.2 (TP 2).

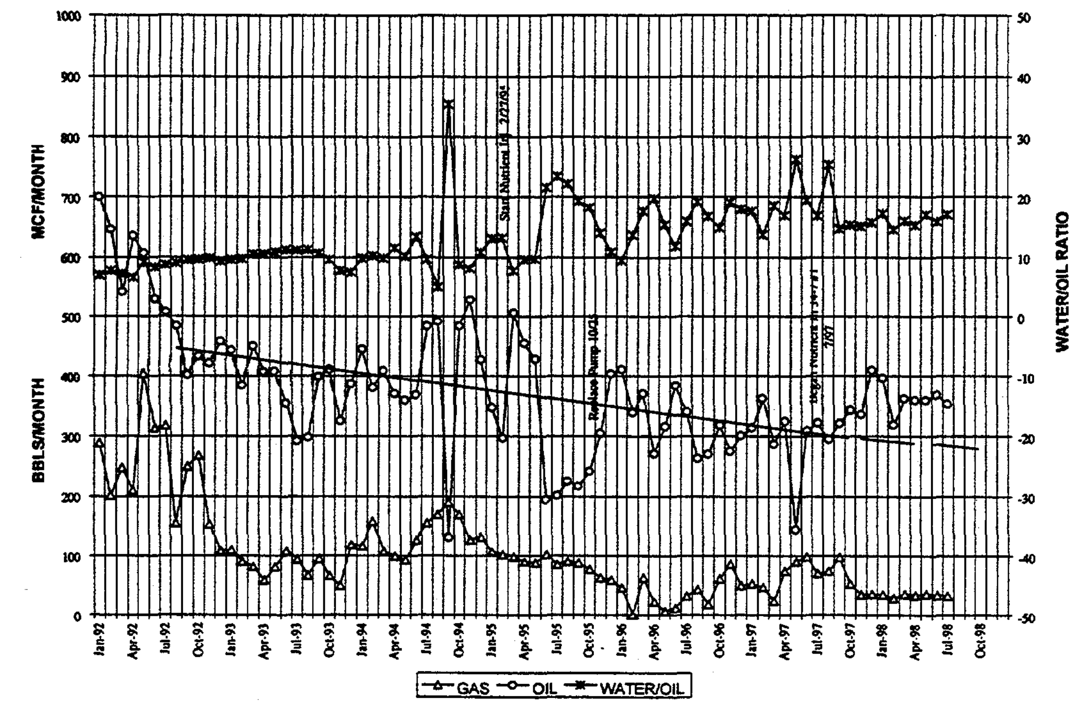

Figure A9. Performance of well 34-10 No.1 (TP 2 and 34-7 No. 1 Nutrient Injectors).

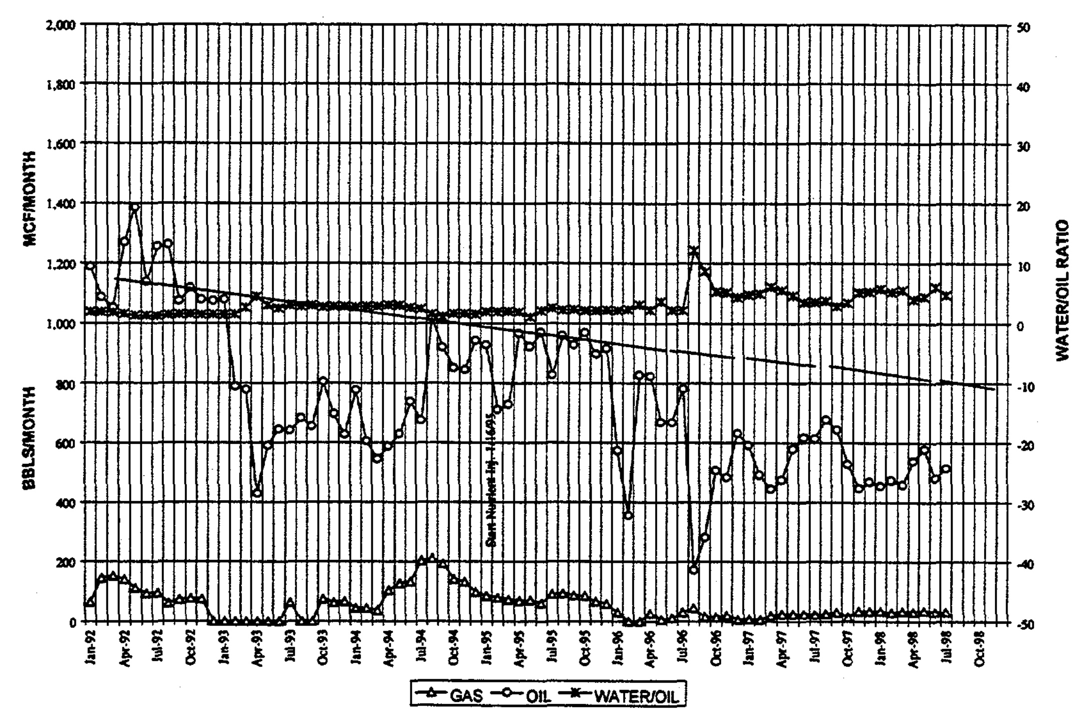

Figure A10. Performance of well 10-8 No.1 (TP 3).

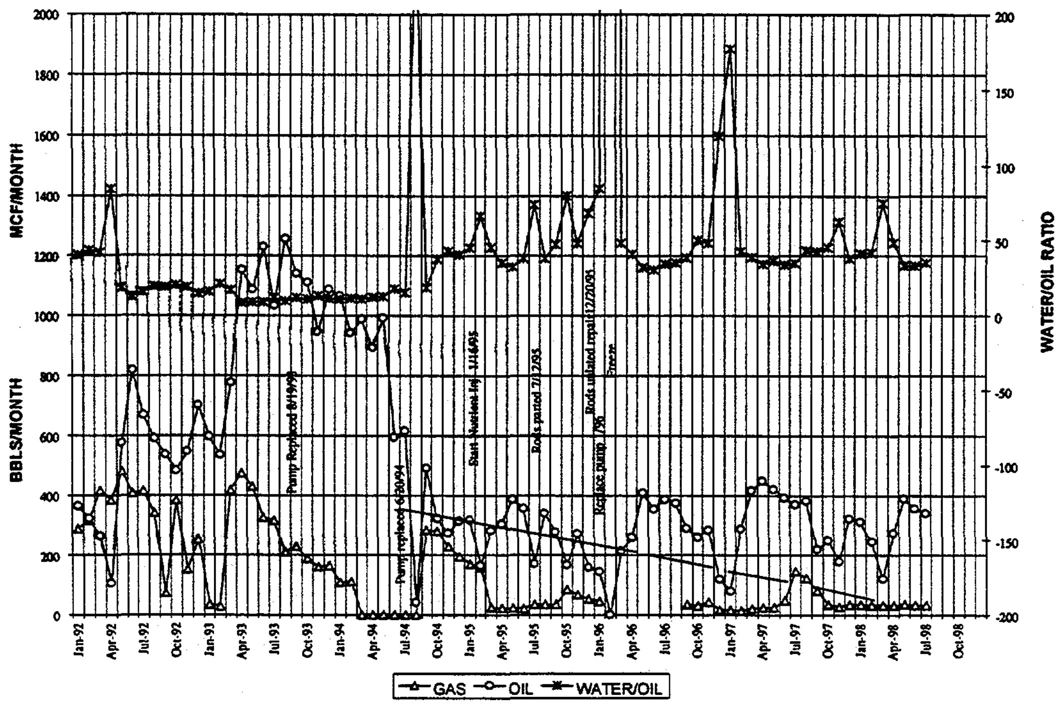

Figure A11. Performance of well 11-6 No.1 (TP 3).

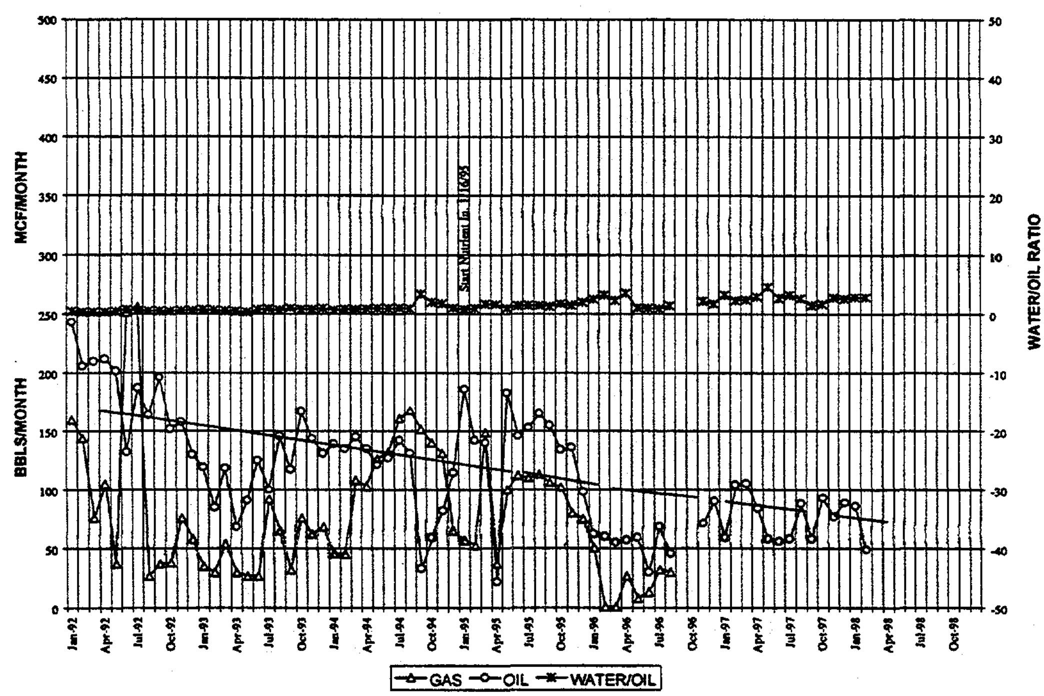

Figure A12. Performance of well 11-4 No.1 (TP 3).

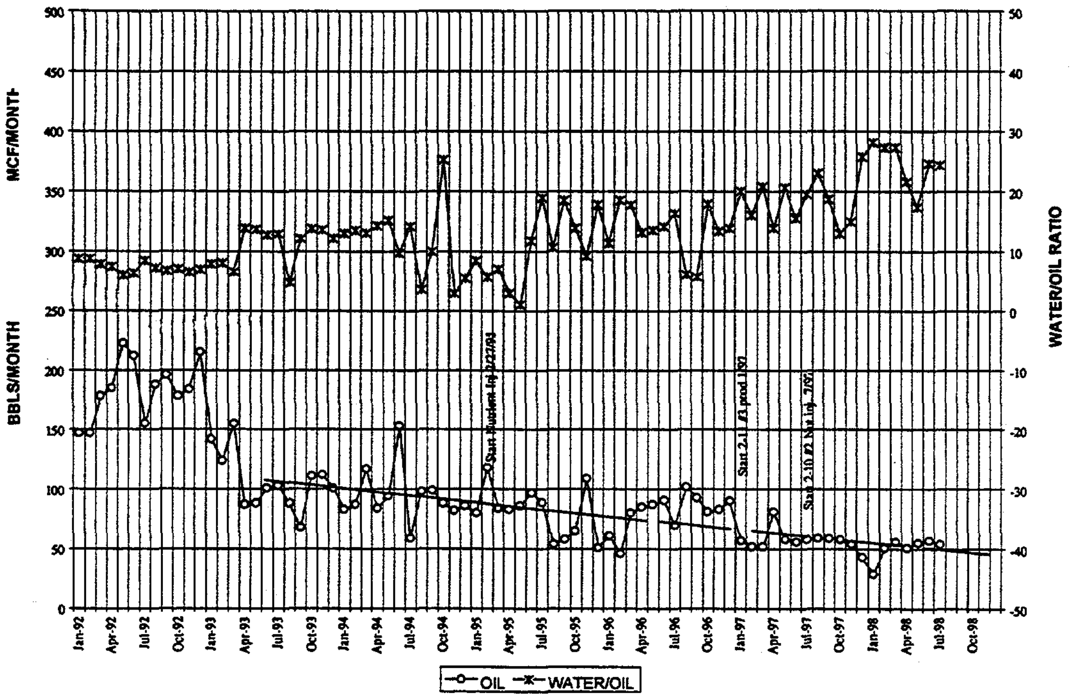

Figure A13. Performance of well 2-11 No.2 (TP 4 and 2-10 No. 2 Injector).

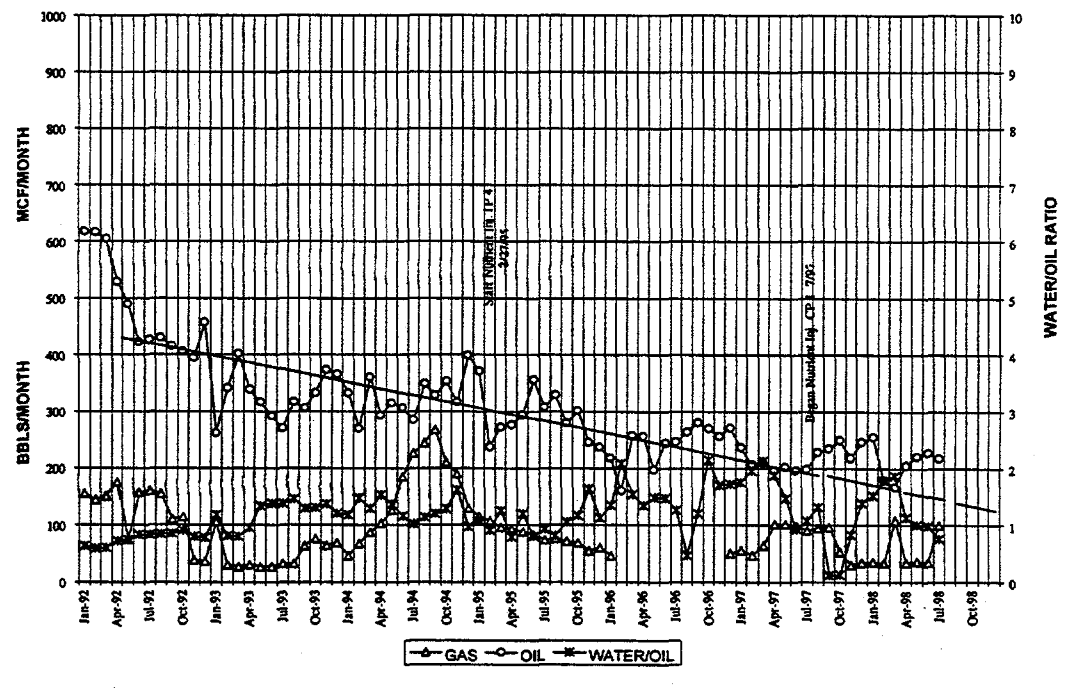

Figure A14. Performance of well 2-3 No.1 (TP 4 and Converted Control Pattern 1).

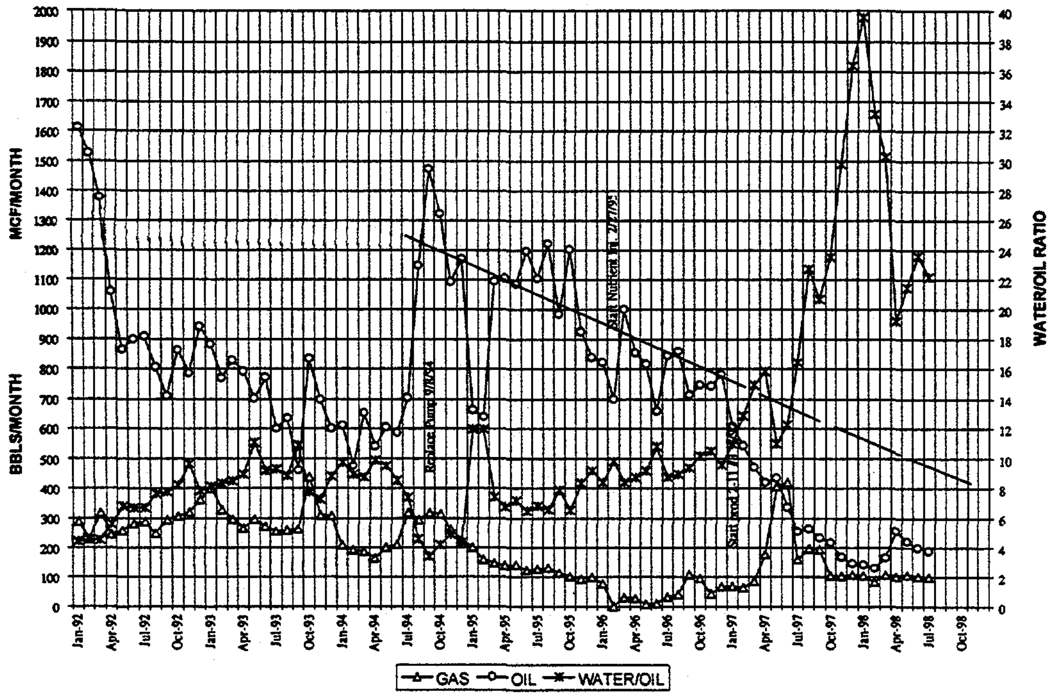

Figure A15. Performance of well 2-5 No.1 (TP 4 and Converted Control Pattern 1).

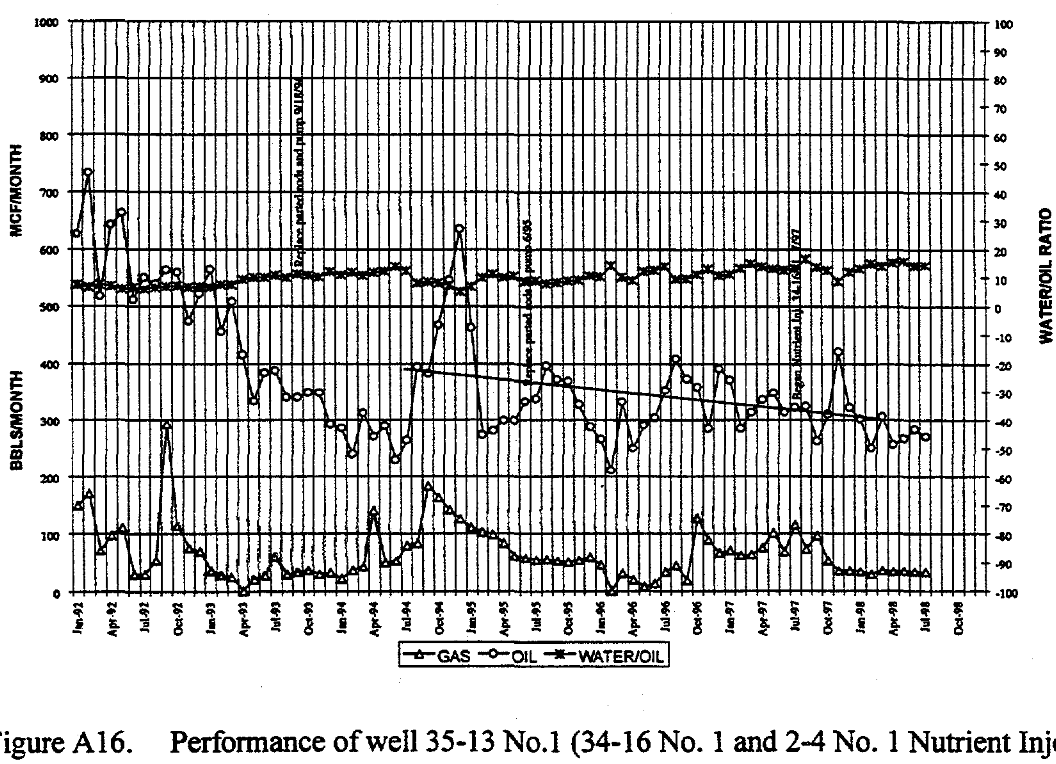

Figure A16. Performance of well 35-13 No.1 (34-16 No. 1 and 2-4 No. 1 Nutrient Injectors).

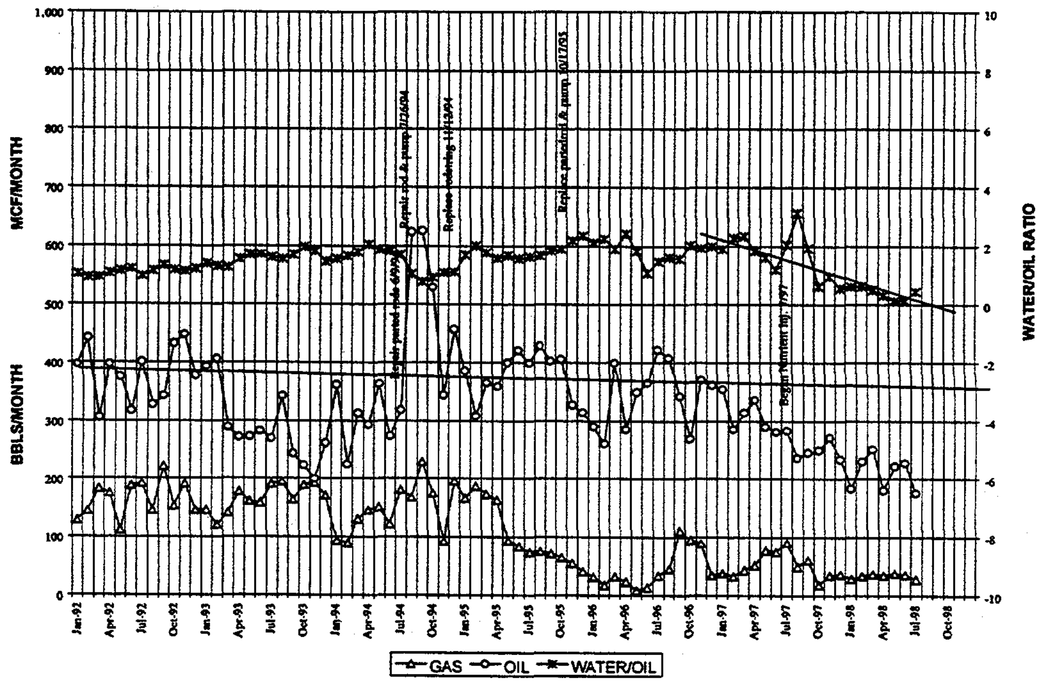

Figure A17. Performance of well 3-1 No.1 (2-4 No. 1 and 34-16 No. 1 Nutrient Injectors).

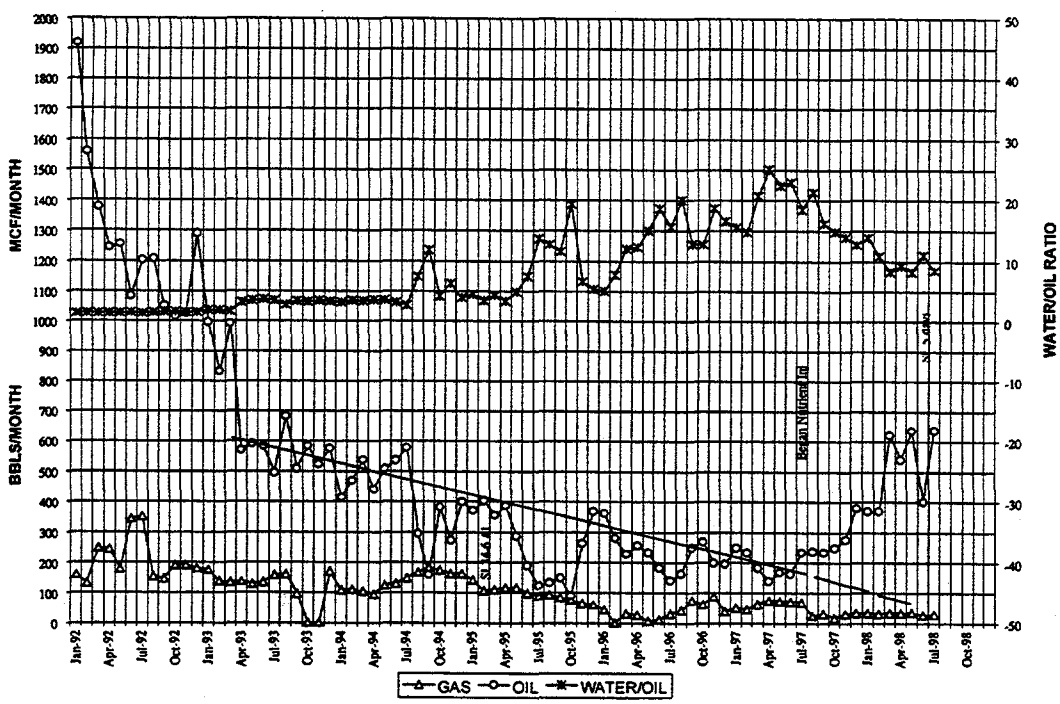

Figure A18. Performance of well 34-2 No.1 (34-7 No. 1 Nutrient Injector).

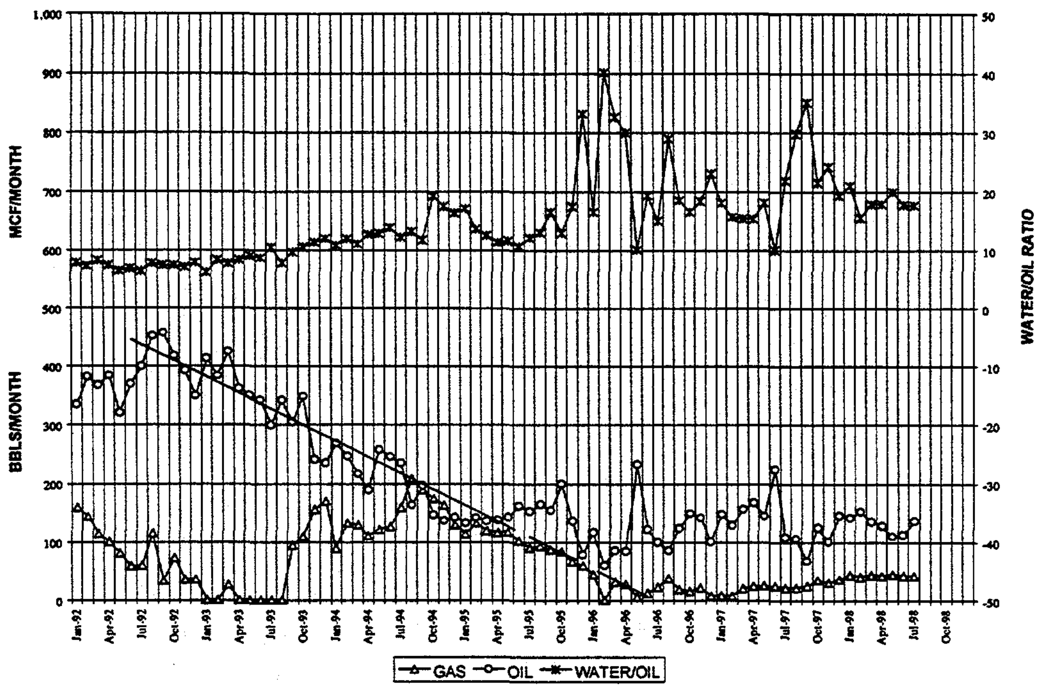

Figure A19. Performance of well 3-3 No.1 (CP 3).

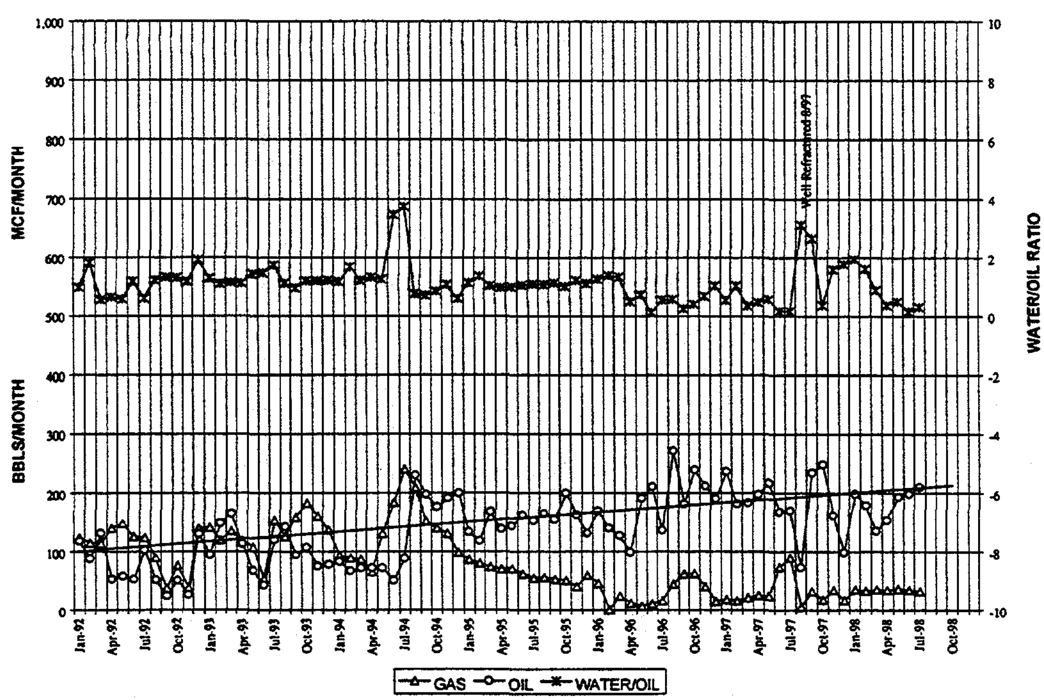

Figure A20. Performance of well 3-1 No.2 (CP 3 and CP 4).

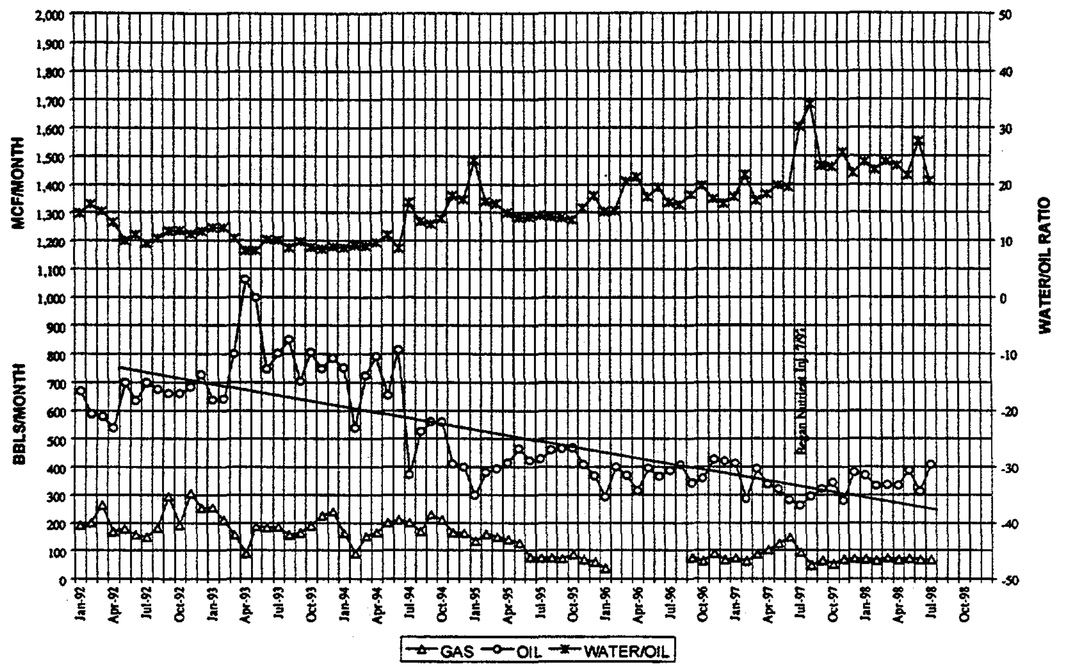

Figure A21. Performance of well 3-9 No.1 (NBCU 2-12 No. 1 and 3-16 No. 1 Nutrient Injectors).

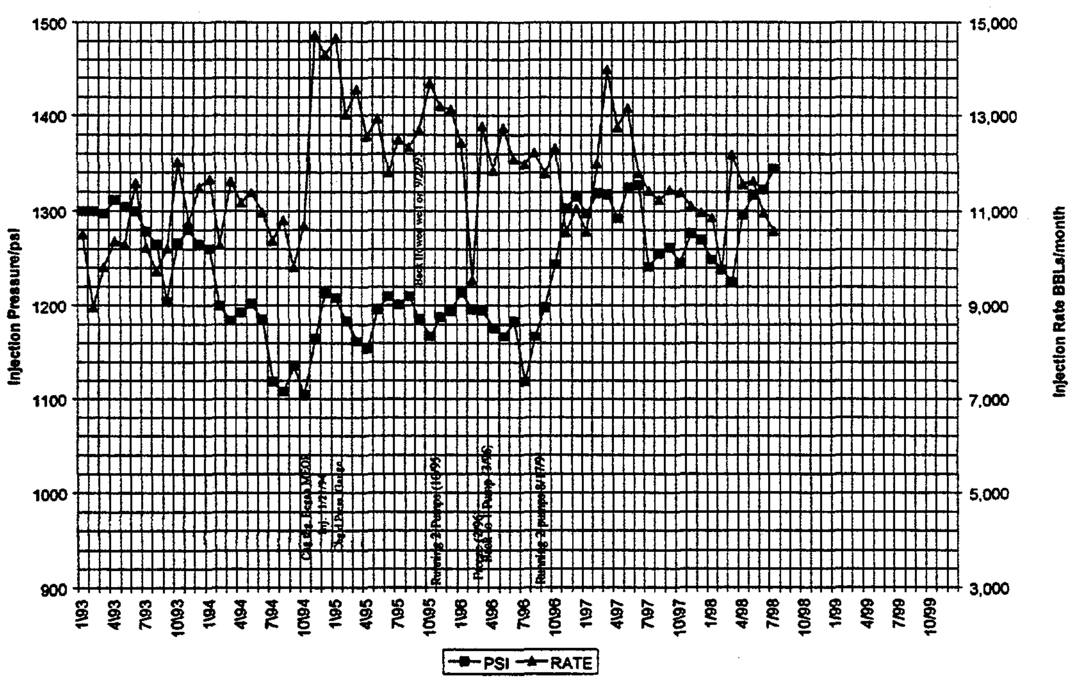

Figure A22. Performance of injection well 2-14 No. 1 (TP 1).

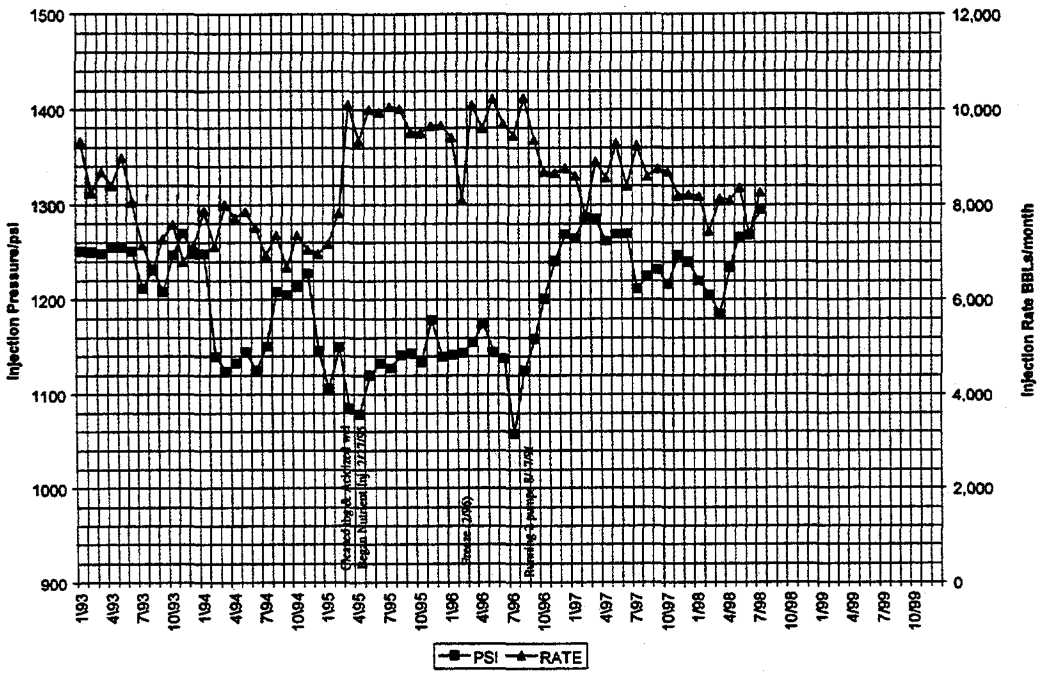

Figure A23. Performance of injection well 34-9 No.2 (TP 2).

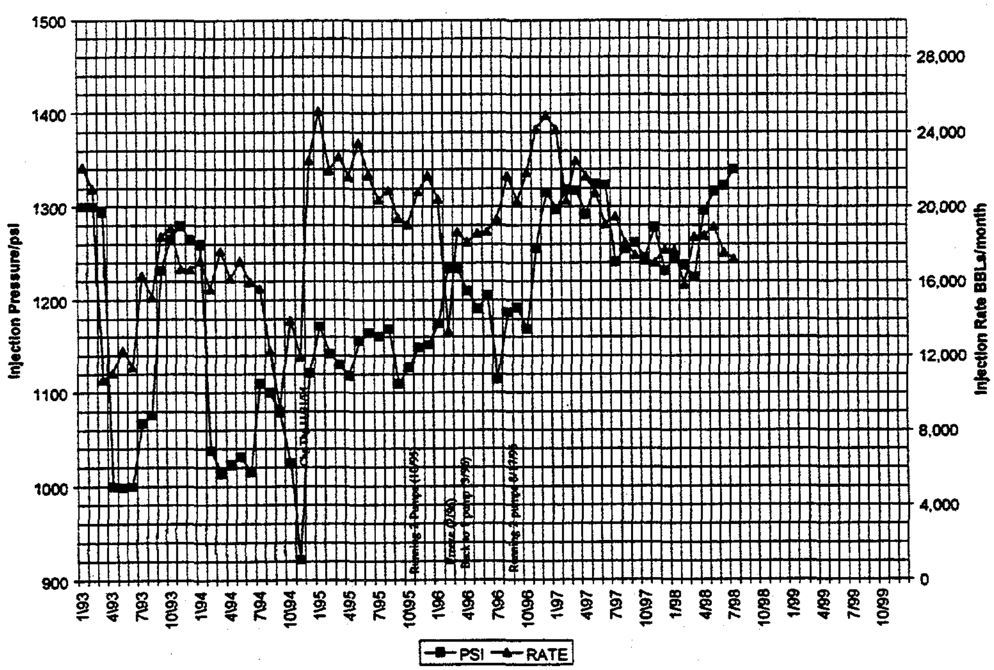

Figure A24. Performance of injection well 11-5 No.1 (TP 3).

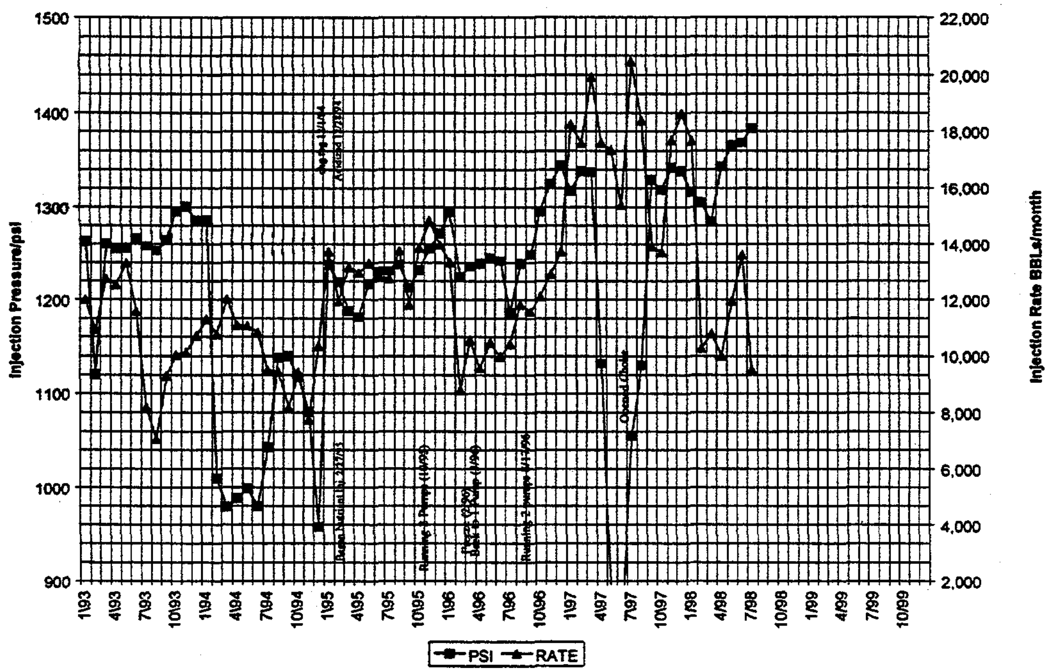

Figure A25. Performance of injection well 2-6 No.1 (TP 4).

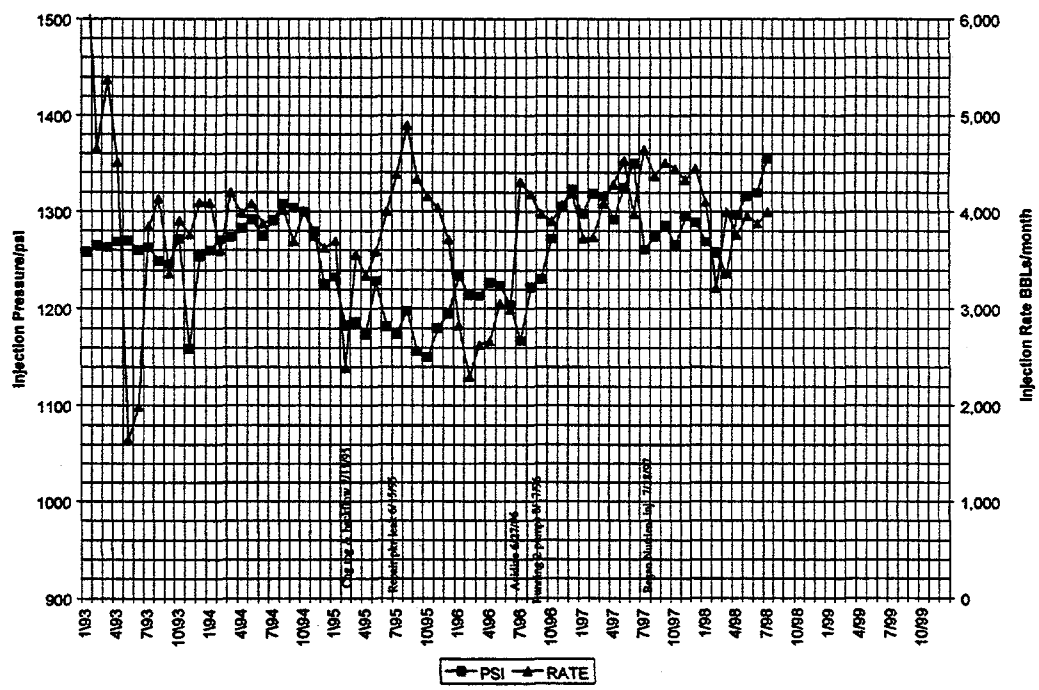

Figure A26. Performance of injection well 2-4 No.1 (was injector for CP 1).

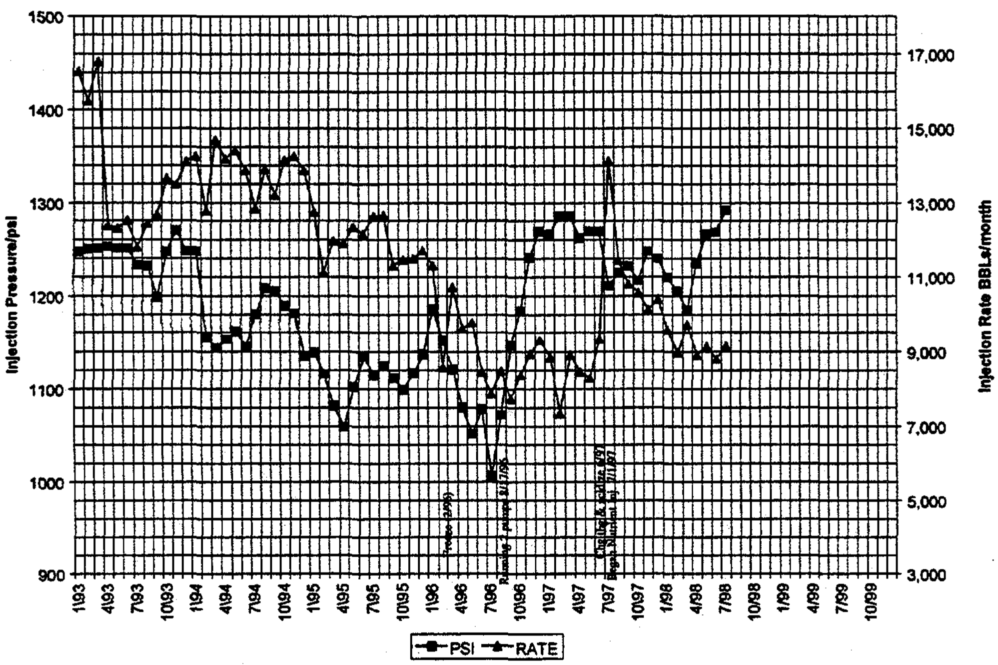

Figure A27. Performance of injection well 34-7 No. 1 (was injector for CP 2).

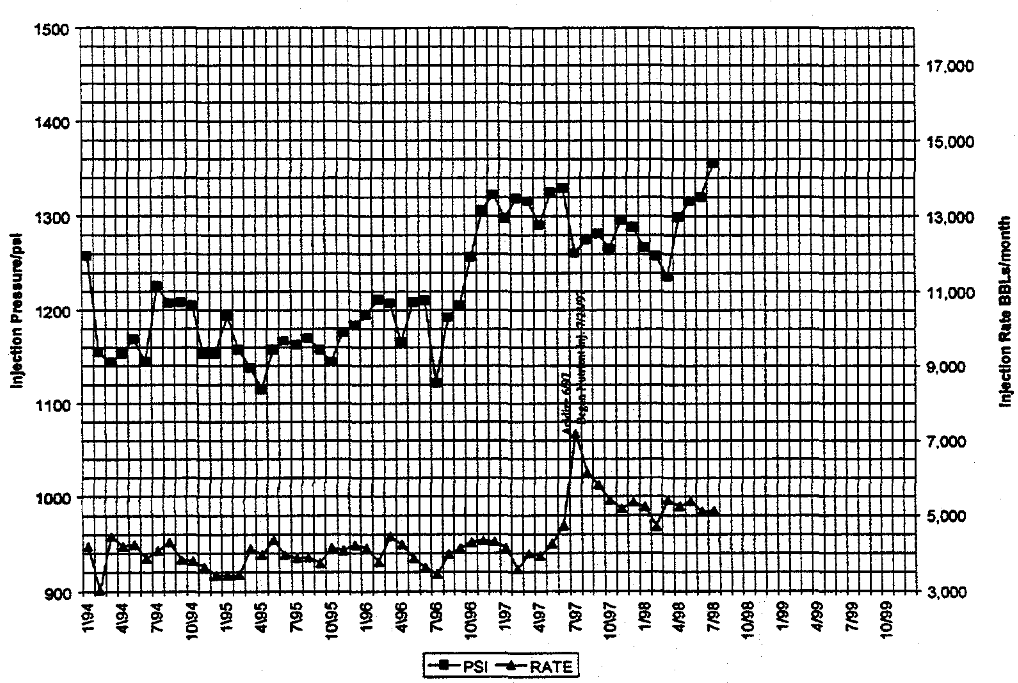

Figure A28. Performance of injection well 34-16 No. 1 (not in original program).

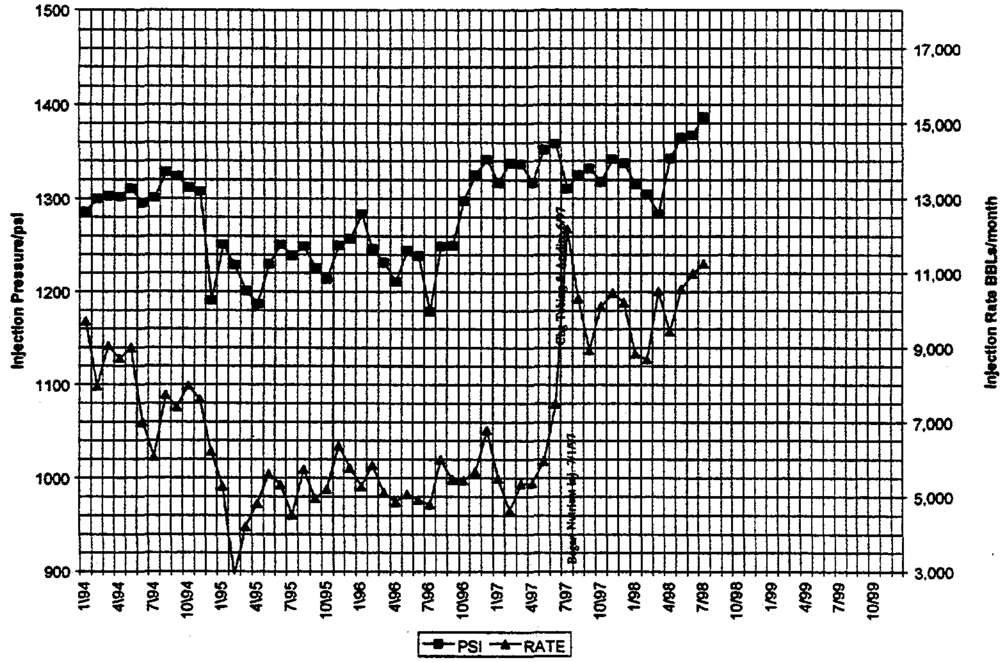

Figure A29. Performance of injection well 2-12 No. 1 (not in original program).

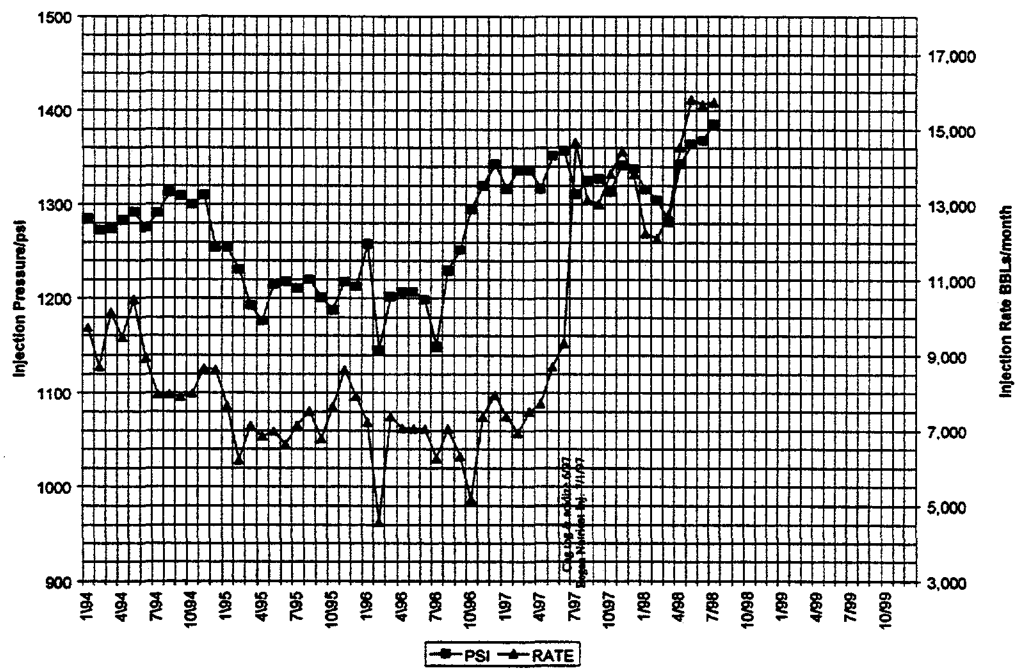

Figure A30. Performance of injection well 3-16 No. 1 (not in original program).

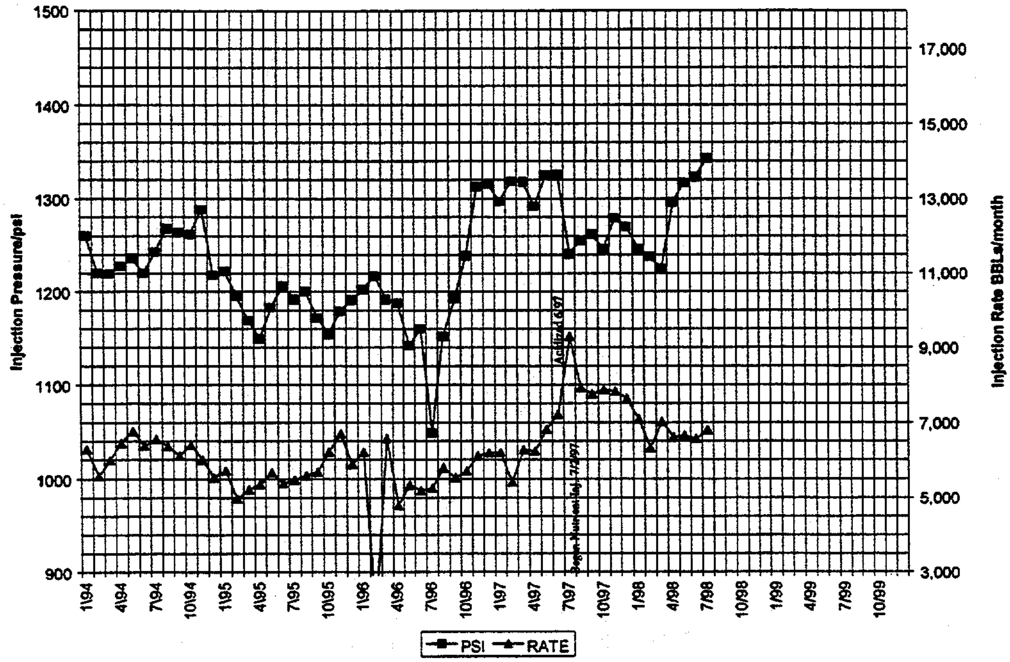

Figure A31. Performance of injection well 2-10 No. 2 (not in original program).