FOSSIL ENERGY

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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

Technical Progress Report
January 1, 1997 - December 31, 1997

By
James O. Stephens

December 1998

Performed Under Contract No. DE-FC22-94BC14962

Hughes Eastern Corporation
Jackson, Mississippi

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

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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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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Rhonda P. Lindsey, Technology Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by:
Hughes Eastern Corporation
Mtel Centre South Building
200 South Lamar Street, Suite 1050
Jackson, MS 39201

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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 fourth 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 nutrients to be used in the field demonstration. The field demonstration involves 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 distributed widely in the reservoir. Microorganisms were shown to be present 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 is improving oil recovery. Of the 15 producer wells in the test patterns, seven have 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 of the 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 has been 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 have shown improved oil production for the last three months. While it would be premature to definitely characterize these two wells as yielding a positive response, these early results are certainly encouraging.

Of special significance is the fact that over 7953 m^3 (50,022 barrels) of incremental oil have been recovered as a result of the MEOR treatment. Further, calculations show that the economic life of the field will be extended until July 2004 instead of a previously anticipated closure in Dec. 2002. 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 project. Preliminary indications are that by increasing the number of injector wells pumping microbial nutrients into the reservoir from four to ten, more oil will be 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.

EXECUTIVE SUMMARY

This project is 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 one-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 fourth annual report covers the findings in months 28-39 of Phase II.

The field demonstration (Phase II) involved injecting nutrients into four injector wells (Test) and comparing the performance of the surrounding producer wells to the 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 in two cases molasses.

In late 1996 three new 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.

Evaluation of oil production data and water:oil ratios (WOR) has shown that seven of the fifteen producer wells in test patterns have 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.

Of special significance is the fact that over 7953 m^3 (50,022 barrels) of incremental oil have been recovered as a result of the MEOR treatment. Further, calculations show that the economic life of the field will be extended until July 2004 instead of a previously anticipated closure in Dec. 2002. 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). Preliminary indications are that by increasing the number of injector wells pumping microbial nutrients into the reservoir from four to ten, more oil will be 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. When those five wells are considered, the total project incremental recovery through 1997 was

17,000 m^3 (107 MBO) and an additional 26,700 m^3 (168 MBO) are expected even with no further response from the six recently added nutrient injectors making total incremental recovery of 43,700 m^3 (275 MBO).

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 growth of the microorganisms to achieve the desired result.

This five and one-half year project is 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-AC22-90BC14665. Work on this project is divided into three phases of nine months, forty-five months, and twelve months, respectively. This Fourth Annual Report will describe the work completed during a twelve-month period of Phase II.

Phase I, with a duration of nine months, has been completed. Two wells were drilled in an area of the field where approximately twenty feet of Carter Sand were expected and where bypassed oil could reasonably be expected to exist. Cores from one well were obtained and employed in laboratory core flood experiments in order to design the protocol for Phase II (Implementation). The schedule and amounts of nutrients employed in the field were formulated on the basis of these laboratory data.

Phase II, with a duration of forty-five months is now nearly completed. The first of four injection skids was built and injection of nutrients into the injector for the first test pattern began on November 21, 1994. The nutrients being injected are potassium nitrate and sodium dihydrogen phosphate and, in two cases, molasses. Injection of nutrients into test patterns two, three, and four was begun on February 27, 1995, January 16, 1995, and February 27, 1995, respectively.

After approximately 30 months of the field tests, results of the project have been so encouraging that the field trial was expanded in June, 1997 to increase the number of test injectors from four to ten.

DISCUSSION

1. OBJECTIVE AND OVERALL PLAN OF WORK

The objective of this work is 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.

This increase in microbial population is accomplished by injecting a nutrient solution into four injectors. Four other injectors will act as control wells. During Phase I, two wells were drilled and one was cored through the pay zone. The cores were employed in core flood experiments in order to arrive at the optimum nutrient formulation and feeding regime. During Phase II, nutrient injection began, the results are being monitored, and adjustments to the nutrient composition made. Phase III will focus on technology transfer of the results.

One expected outcome of this new technology will be a prolongation of economical waterflooding operations, i.e. economical oil recovery should continue for much longer periods in 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 3.24×10^5 m^2 (80 acre) spacing. The field was unitized into a reservoir-wide unit in 1983 and in-fill drilled to 1.62×10^5 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. Currently there are 20 injection wells and 33 producing wells. Current production is 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 current water injection rate is about 650 m^3/d of water (4150 BWPD). About 1.6 m^3 of oil (10 MMBO) will be left unrecovered if some method of enhanced recovery is not proven to be feasible.

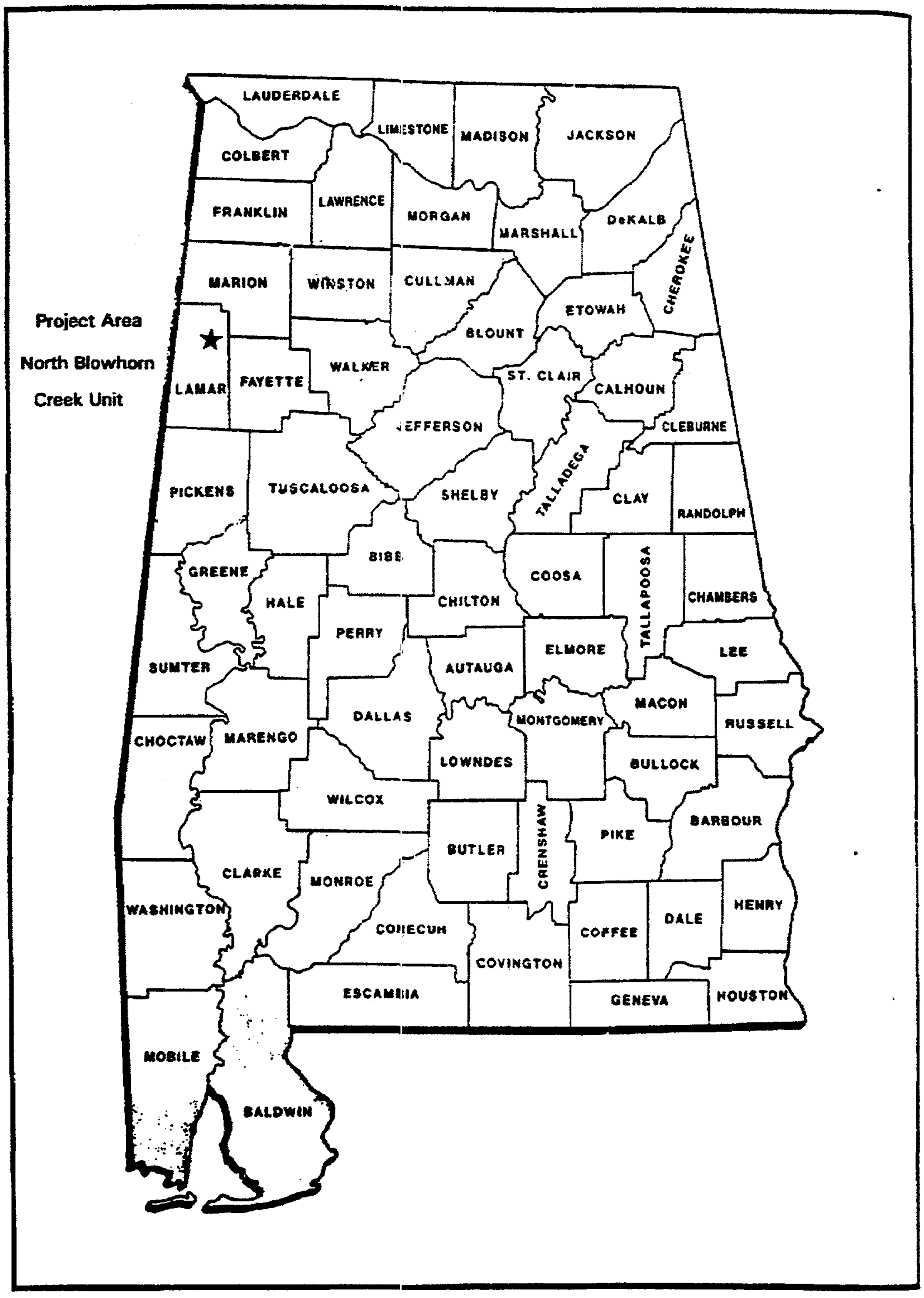

Figure 1. Project area geographical locator map.

3. PHASE II. IMPLEMENTATION

a. Design of Field Demonstration

(1). Test patterns for field demonstration

Although the test patterns for the field demonstration were given in last year's Annual Report they will be repeated here for sake of completeness. The wells included in the patterns are as follows.

TP 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 1 (Control Set)

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

TP 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 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 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 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 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 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). Expansion of the field demonstration

It became apparent after 30 months of monitoring, that producer wells (8), not influenced by the injection of nutrients into nearby injector wells, have continued their historic natural decline in oil production rate. Contrariwise, nearly half of the wells (15) in areas being waterflooded with microbial nutrients are exhibiting 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.

(3). Feed and feeding regime

After a careful evaluation of the field results, it was decided to modify the feeding regimes for a second time. Table 1 gives the original feeding regime, while Table 2 gives the feeding regime employed from April 1996 - June 1997. The feeding regime being employed since July 1997 is shown in Table 3.

(4). Tracer studies

As reported in the 1995 Annual Report, 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 have produced detectable amounts of the tracer.

(5). Drilling of three additional wells

Three new 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 in-situ growth of microorganisms by analysis of recovered core samples and produced fluids. The locations of the wells can be seen 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 Dual Induction and Density-Neutron log sections are shown in Figure 3 and the conventional core analysis is shown in Figure 4. 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. The 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 0.16 m^3 oil/day (1 BOPD) and 1.75 m^3 water/day (11 BWPD).

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 m (2180 and 2205 ft) and 9.7 m (32 ft) of core were recovered. Sections of the Dual Induction and Density-Neutron logs are shown in Figure 5 and the conventional core analysis is shown in Figure 6. The core analysis indicates much higher permeability in the

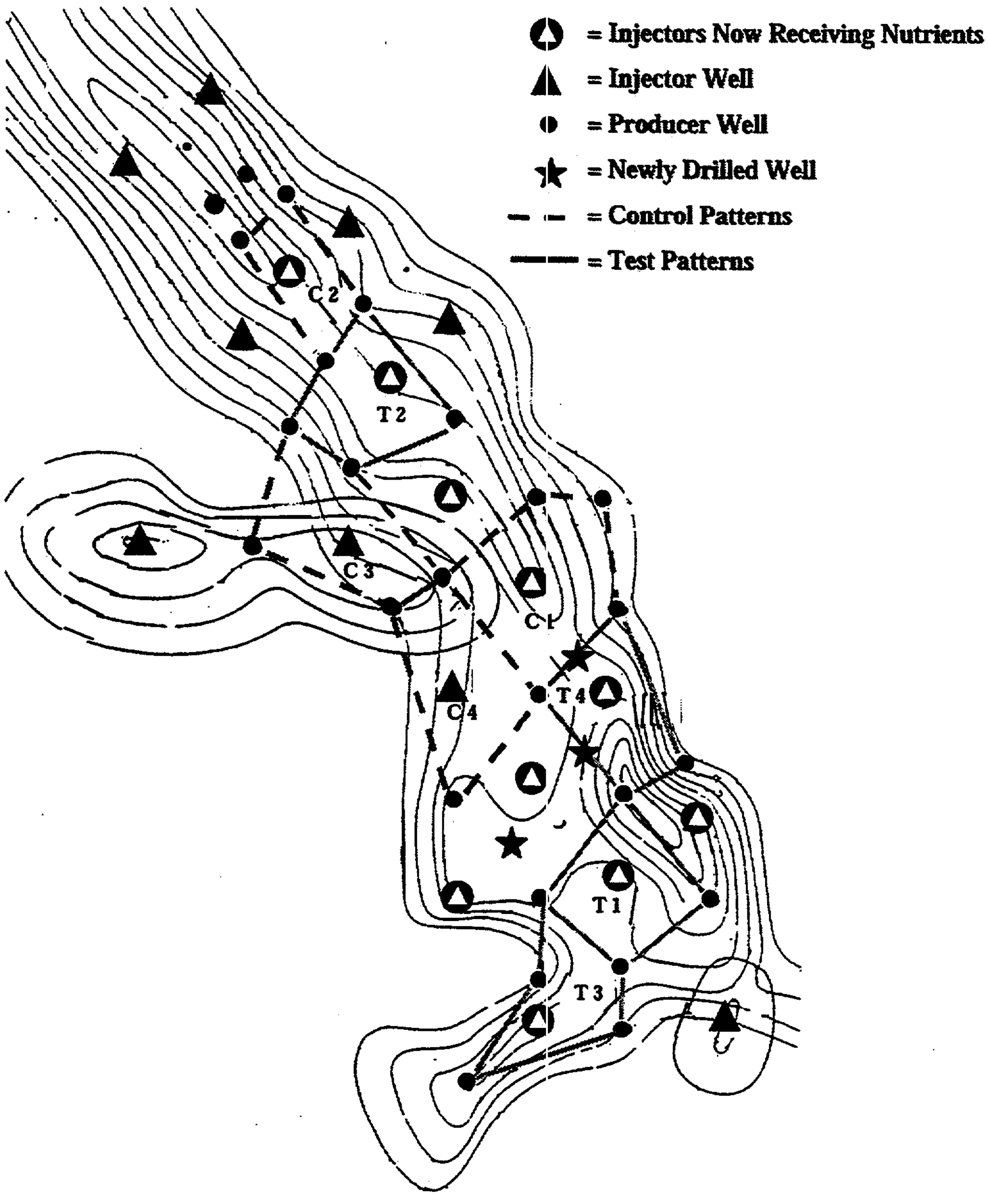

Figure 2. Location of injector wells now receiving nutrients.

Table 1. 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		0.1%(v/v) Wednesdays	same as 1	same as 2

Table 2. Feed and Feeding Regime From May 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

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		0.32 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		0.04 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).

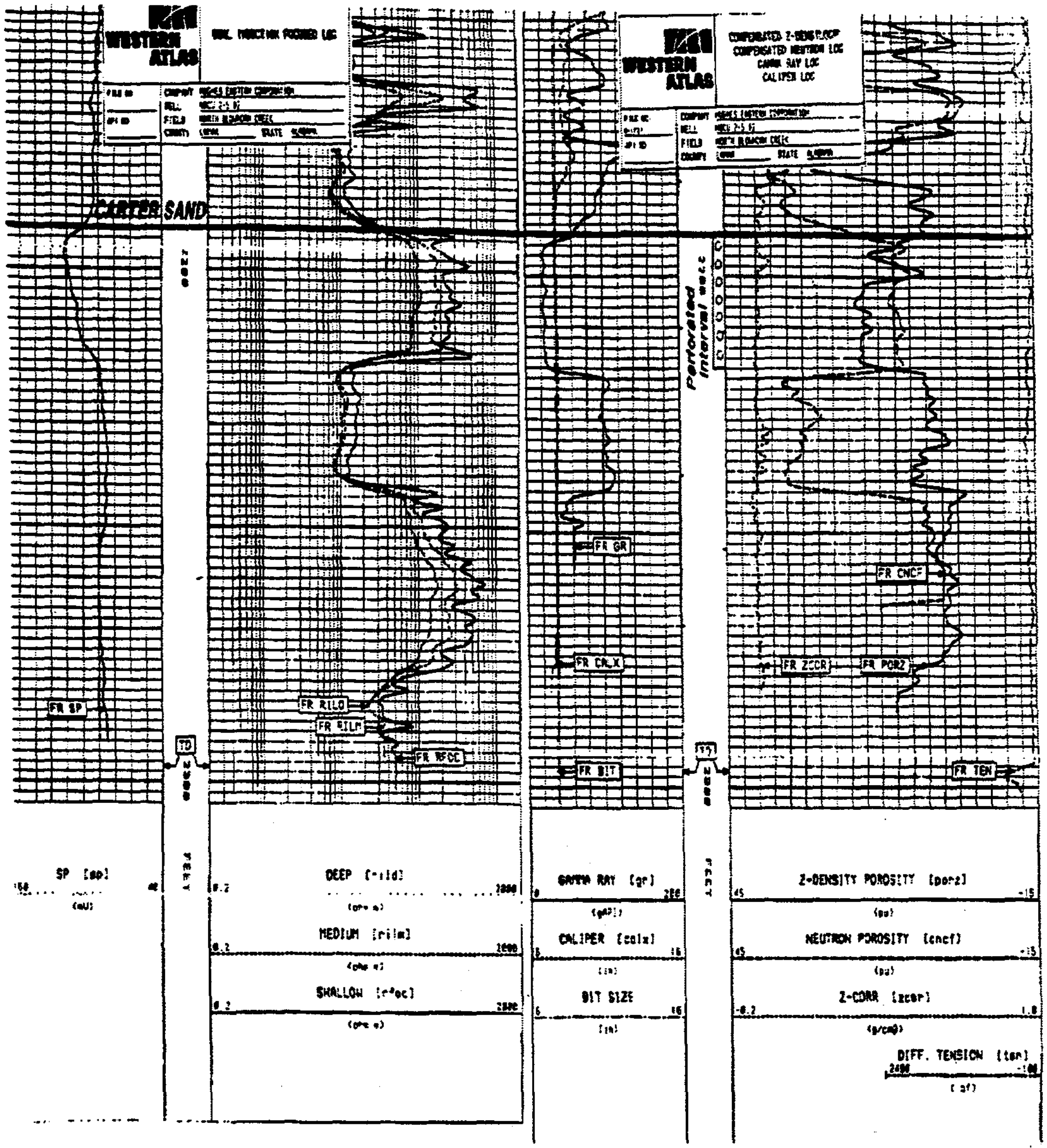

Figure 3. NBCU 2-5 No.2 log sections.

HUGHES EASTERN COPORATION
NBCU 2-5 #2

LAMAR COUNTY ALABAMA

CORETECH

CONVENTIONAL CORE

FILE NO.: 96102C
PERMIT NO:
LAB: Jackson MS
ANALYST: McGlaun

SMP NO.	DEPTH FEET	PERM md (Kl)	PERM md (Ka)	FLD POR	HEL POR	OIL% PORE	W1R% PORE	PROB PROD	DESCRIPTION	Bcfw%	FLU	GRN DEN
OCT. 16, 1996 HUGHES EASTERN CORPORATION 43 FEET CORED												
1	2185.0 - 85.5			1.6		0.8	11.9	LP	SHALE DRK GRY SD LAMS		NO	
2	2186.0 - 86.5			1.7		0.0	75.9	LP	SHALE DRK GRY SD LAMS		NO	
3	2187.0 - 87.5			2.8		0.0	51.0	LP	SHALE DRK GRY SD LAMS		NO	
4	2188.0 - 88.5			2.7		0.0	84.6	LP	SHALE DRK GRY SD LAMS		NO	
5	2189.0 - 89.5		*7.5	3.7	6.5	3.0	51.0	LP	SHALE DRK GRY SD LAM S/ASPH		FT	2.70
6	2190.0 - 90.5		*7.9	3.7	3.7	0.0	70.7	LP	SHALE DRK GRY SD LAM S/ASPH		FT	2.69
7	2191.0 - 91.5			10.1		12.2	63.4	LP	SHALE DRK GRY SD LAMS		FT	
8	2192.0 - 92.5			2.4		0.0	52.8	LP	SHALE DRK GRY SD LAMS		FT	
9	2193.0 - 93.5		*6.5	2.3	3.7	0.0	56.5	LP	SD GRY/WHT VFG S/SHLY S/ASPH		FT	2.70
10	2194.0 - 94.5		*4.2	2.5	4.5	0.0	51.6	LP	SD GRY/WHT VFG S/SHLY S/ASPH		FT	2.68
11	2195.0 - 95.5		*7.2	4.8	4.3	31.3	26.1	OIL	SD GRY/WHT VFG S/SHLY S/ASPH		FT	2.70
12	2196.0 - 96.5		7.80	12.4	8.5	23.8	46.4	OIL	SD BRN VFG S/SHLY S/ASPH	51	FT	2.62
13	2197.0 - 97.5		36.00	12.2	14.6	11.3	31.9	OIL	SD BRN/GRY VFG S/SHLY ASPH	46	YELLOW	2.61
14	2198.0 - 98.5		22.00	15.9	14.8	11.0	28.2	OIL	SD BRN/GRY VFG ASPH	54	YELLOW	2.63
15	2199.0 - 99.5		10.70	9.2	12.3	5.2	12.9	OIL	SD BRN/GRY VFG ASPH	53	YELLOW	2.68
16	2200.0 - 0.5		0.70	3.6	4.3	31.7	28.1	LP	SD BRN/GRY VFG ASPH		YELLOW	2.74
17	2201.0 - 1.5		0.40	2.9	2.5	42.7	25.6	LP	SD BRN/GRY VFG ASPH		YELLOW	2.73
18	2202.0 - 2.5		20.00	15.4	13.8	15.2	36.1	OIL	SD BRN/GRY VFG ASPH	51	YELLOW	2.64
19	2203.0 - 3.5		24.00	13.4	13.9	15.4	35.9	OIL	SD BRN/GRY VFG ASPH Api 30.6	49	YELLOW	2.63
20	2204.0 - 4.5		8.90	12.7	12.1	20.4	38.3	OIL	SD BRN/GRY VFG ASPH SHLY LAM	54	YELLOW	2.63
21	2205.0 - 5.5		9.70	16.1	12.4	13.9	33.1	OIL	SD BRN/GRY VFG ASPH SHLY LAM	53	YELLOW	2.63
22	2206.0 - 6.5		26.00	14.0	14.9	14.7	26.1	OIL	SD BRN/GRY VFG ASPH	51	YELLOW	2.62
23	2207.0 - 7.5		11.60	17.3	12.9	11.6	23.3	OIL	SD BRN/GRY VFG ASPH SHLY LAM	54	YELLOW	2.62
24	2208.0 - 8.5		32.00	14.7	15.4	13.9	29.3	OIL	SD BRN/GRY VFG ASPH	48	YELLOW	2.61
25	2209.0 - 9.5		50.00	19.5	15.4	7.2	18.8	OIL	SD BRN/GRY VFG ASPH SHLY LAM	44	YELLOW	2.63
26	2210.0 - 10.5		10.30	15.5	13.5	13.1	26.2	OIL	SD BRN/GRY VFG ASPH	54	YELLOW	2.66
27	2211.0 - 11.5		18.00	12.3	13.9	17.2	36.2	OIL	SD BRN/GRY VFG ASPH	52	YELLOW	2.65
28	2212.0 - 12.5		13.00	10.9	12.9	10.8	32.3	OIL	SD BRN/GRY VFG ASPH SHLY LAM	52	YELLOW	2.63
29	2213.0 - 13.5		13.00	12.4	12.5	17.4	34.7	OIL	SD BRN/GRY VFG ASPH SHLY LAM	52	YELLOW	2.69
30	2214.0 - 14.5		13.00	12.3	11.8	9.6	13.4	OIL	SD BRN/GRY VFG ASPH Api 29.6	52	YELLOW	2.64
31	2215.0 - 15.5		38.00	8.8	14.4	8.0	18.7	OIL	SD BRN/GRY VFG ASPH	47	YELLOW	2.68

Figure 4. NBCU 2-5 No.2 conventional core analysis.

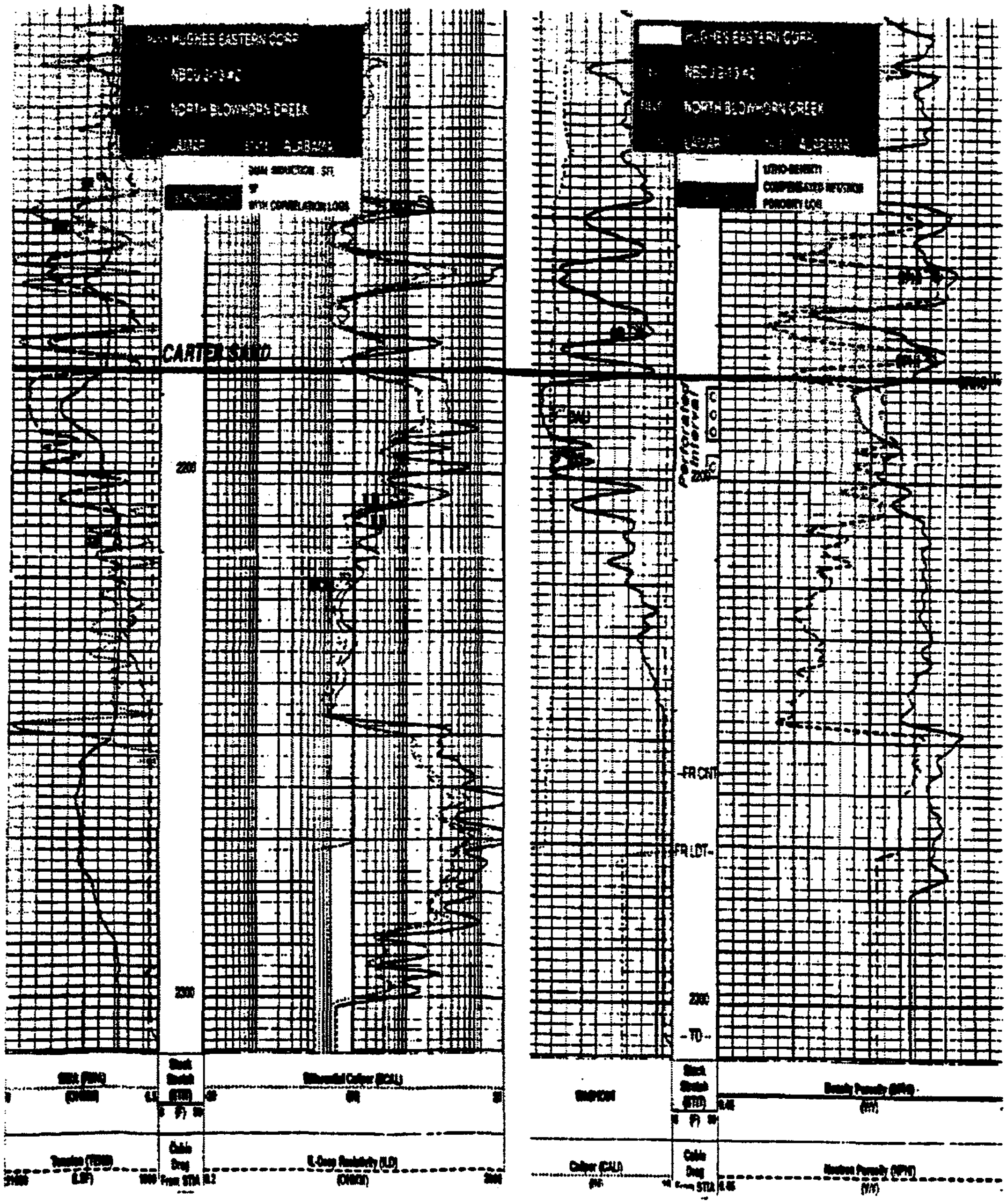

Figure 5. NBCU 2-13 No.2 log sections.

HUGHES EASTERN CORPORATION
NBCU 2-13 #2
2-14S 14W
NORTH BLOWHORN CREEK
LAMAR COUNTY ALABAMA

CORETECH

FILE NO.: 96104C
PERMIT NO:
LAB: Jackson, MS
ANALYST: McGlaun

SMP NO.	DEPTH FEET	PERM md (K)	PERM md (Ka)	FLD POR	HEL POR	OIL% PORE	WTR% PORE	PROB PROD	DESCRIPTION	Sol%	FLU	GRN DEN
10-28-96 HUGHES EASTERN CORP 43 FEET CORED												
	2172.0 - 173.0								SHALE DK GRY		NO	
	2173.0 - 174.0								SHALE DK GRY		NO	
	2174.0 - 175.0								SHALE DK GRY		NO	
1	2175.0 - 176.0		1.00	1.2	2.4	0.0	61.6	LP	SD GRY/ WHT VFG		NO	2.71
2	2176.0 - 177.0		0.70	1.0	1.8	0.0	61.7	LP	SD GRY/ WHT VFG		NO	2.74
3	2177.0 - 178.0		0.70	0.4	0.7	0.0	60.3	LP	SD GRY/ WHT VFG SH LAMS		NO	2.71
4	2178.0 - 179.0		0.70	0.5	0.3	0.0	51.9	LP	SD GRY/ WHT VFG SH LAMS		NO	2.69
5	2179.0 - 180.0		1.50	2.6	3.9	0.0	56.3	LP	SD GRY/ WHT VFG SH LAMS		NO	2.69
	2180.0 - 181.0								SHALE DK GRY		NO	
	2181.0 - 182.0								SHALE DK GRY		NO	
	2182.0 - 183.0								SHALE DK GRY		NO	
	2183.0 - 184.0								SHALE DK GRY		NO	
6	2184.0 - 185.0		22.00	7.2	8.6	16.4	31.6	OIL	SD BRN VF- FG ASPH	42	YELLOW	2.63
7	2185.0 - 186.0		141.00	11.9	13.9	9.8	24.3	OIL	SD BRN VF- FG ASPH	33	YELLOW	2.59
8	2186.0 - 187.0		50.00	11.1	12.6	20.1	21.3	OIL	SD BRN VF- FG ASPH	40	YELLOW	2.60
9	2187.0 - 188.0		87.00	12.8	13.3	14.5	22.5	OIL	SD BRN VF- FG ASPH	39	YELLOW	2.58
10	2188.0 - 189.0		86.00	13.6	14.4	9.7	19.8	OIL	SD BRN VF- FG ASPH	39	YELLOW	2.60
11	2189.0 - 190.0		91.00	13.0	14.7	5.2	23.7	OIL	SD BRN VF- FG ASPH	38	YELLOW	2.60
12	2190.0 - 191.0		101.00	13.3	14.9	11.9	24.5	OIL	SD BRN VF- FG ASPH	37	YELLOW	2.60
13	2191.0 - 192.0		43.00	10.8	11.6	15.2	18.1	OIL	SD BRN VF- FG ASPH	41	YELLOW	2.62
14	2192.0 - 193.0		107.00	13.1	14.9	11.7	20.7	OIL	SD BRN VF- FG ASPH	38	YELLOW	2.62
15	2193.0 - 194.0		44.00	12.8	12.6	12.9	20.5	OIL	SD BRN VF- FG ASPH	43	YELLOW	2.63
16	2194.0 - 195.0		7.30	8.7	9.5	20.2	21.9	OIL	SD BRN FG ASPH S/SHLY	51	YELLOW	2.63
17	2195.0 - 196.0		1.00	7.6	6.8	16.9	26.3	OIL	SD GRY/ BRN VFG V/SHLY S/ASPH	58	YELLOW	2.64
18	2196.0 - 197.0		4.40	2.9	2.6	8.6	31.6	OIL	SD GRY VFG SH LAMS S/ASPH		FT YEL	2.66
19	2197.0 - 198.0		28.00	9.4	9.1	15.9	26.3	OIL	SD BRN VFG ASPH	42	YELLOW	2.61
20	2198.0 - 199.0		34.00	9.1	9.9	7.7	22.3	OIL	SD BRN VFG ASPH	41	YELLOW	2.62
21	2199.0 - 200.0		11.10	8.9	9.8	11.6	26.7	OIL	SD WHT/GRY VFG	49	YELLOW	2.59
22	2200.0 - 201.0		7.00	3.3	5.3	17.0	23.9	OIL	SD WHT/GRY SHLY LAMS S/ASPH	46	YELLOW	2.63
23	2201.0 - 202.0		4.80	8.1	9.4	29.2	24.4	OIL	SD BRN VFG ASPH	54	YELLOW	2.63
24	2202.0 - 203.0		4.60	9.7	9.5	18.6	21.9	OIL	SD BRN VFG ASPH	54	YELLOW	2.62
25	2203.0 - 204.0		1.90	7.6	8.0	30.5	22.7	OIL	SD WHT/GRY VFG S/ ASPH	56	FT YEL	2.60
	2204.0 - 205.0								SHALE DK GRY		NO	
26	2205.0 - 206.0		1.30	5.8	5.4	0.0	31.4	LP	SD WHT/ GRY VFG V/SH LAMS	56	NO	2.63
27	2206.0 - 207.0		1.30	7.5	7.8	27.0	33.2	OIL	SD GRY VFG S/SHLY ASPH	58	YELLOW	2.64
28	2207.0 - 208.0		1.90	7.6	7.4	18.5	34.1	OIL	SD GRY VFG S/SHLY	55	YELLOW	2.63
29	2208.0 - 209.0		2.40	7.8	7.9	29.8	31.2	OIL	SD GRY VFG S/SHLY S/ASPH	56	YELLOW	2.63
30	2209.0 - 210.0		1.60	3.4	3.9	9.4	33.1	OIL	SD GRY VFG S/SHLY S/ASPH	57	YELLOW	2.66
	2210.0 - 215.0								SHALE DK GRY			

Figure 6. NBCU 2-13 No.2 conventional core analysis.

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 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 in January. Oil production has been relatively steady at 2.4-3.2 m^3 oil/day (15-20 BOPD) with 1.4-4.0 m^3 water/day (9-25 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. Log sections are shown in Figure 7. 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. The conventional core analysis is shown in Figure 8. It is 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. 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. 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 that 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).

b. Chemical and Microbiological Analyses of Core Samples

Chemical and microbiological analyses of core samples from the three newly drilled wells were begun in the fourth quarter of 1996. A total of 16 one-foot (approx.) sections of the core from each well was obtained for chemical and microbiological analyses. Each of ten sections from each core was placed in a large open plastic bag and immediately placed in an anaerobic container and held under anaerobic conditions. Six additional sections were each placed in a closed plastic bag and stored in a one-gallon plastic container (aerobic).

(1) Methods employed

Five sections of core samples from newly drilled wells 2-5 No. 2, 2-13 No. 2, and 2-11 No. 3 were prepared for analyses as follows. Portions of each core section were crushed at 20,000 psi and sieved through a U.S.A. Standard Testing Sieve No. 40 (0.419 opening in mm). One hundred

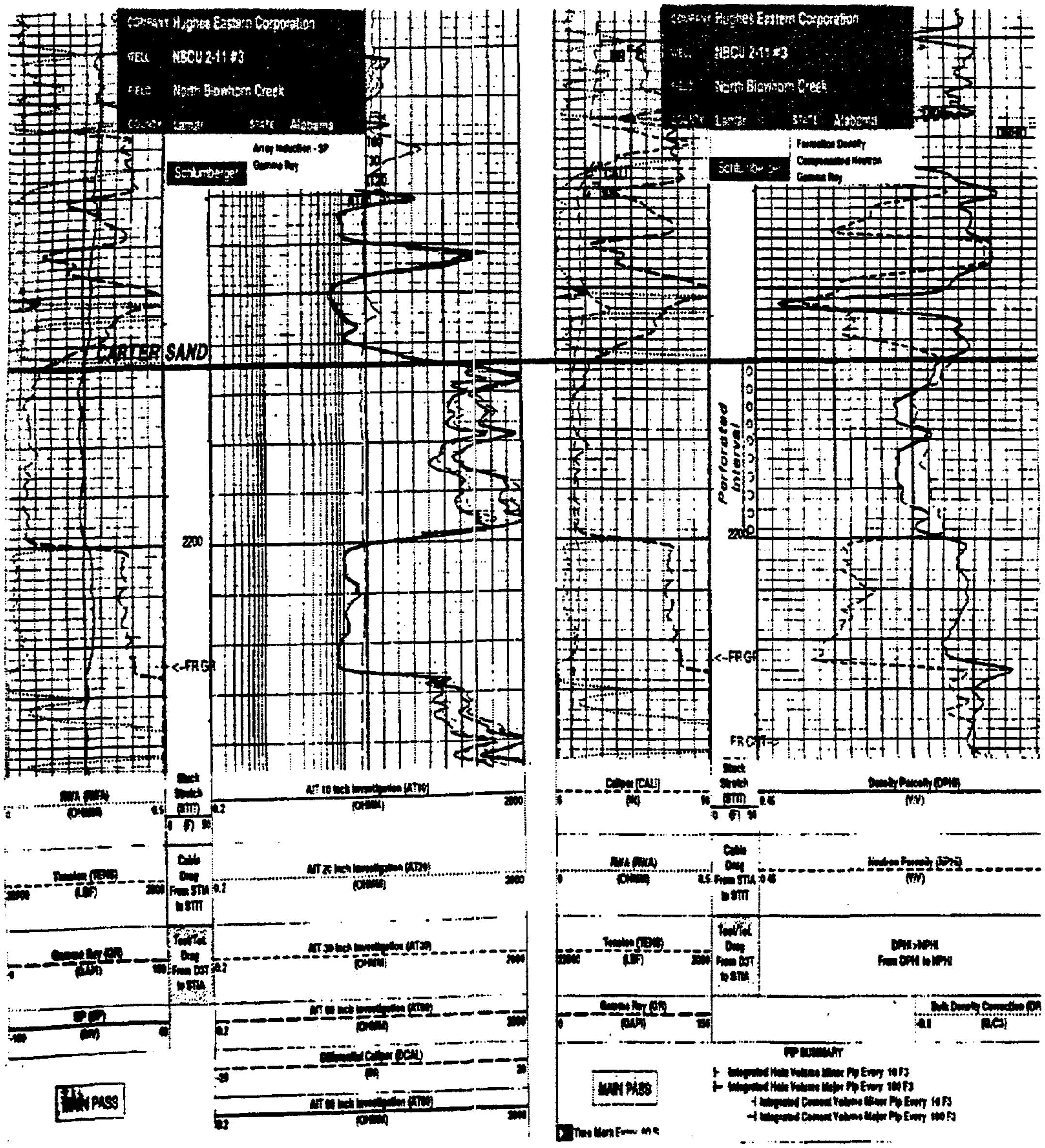

Figure 7. NBCU 2-11 No.3 log sections.

CoreTech, Inc.

Jackson, Mississippi
1-800-748-8031 watts - 601-939-3200 tel. - 601-939-0903 fax.

Core No.1 2170.0-2202.0

Hughes Eastern Corp. | | 981102
NBCU 2-11 #3 | Final Report | 2-14S-14W
North Blowhorn Creek | | Water
Lamar Co., AL. | | McGlaun

Smp. No.	Depth Feet	Perm md.	He Por%	Fluid Por%	So%	Stw%	Prob. Prod.	Ob.%	Gb.%	Description	Flu	Grain Density
1	2170.0 - 70.5	2.57	6.6	9.3	23.6	15.7	OIL	2.2	5.8	SD BRN VFG SHY LAMS S/ASPH	Y	2.62
2	2171.0 - 72.0	2.93	6.8	10.3	14.1	18.7	OIL	1.4	6.9	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
3	2172.0 - 73.0	39.11	6.3	7.6	32.6	32.6	OIL	2.5	2.6	SD BRN VFG SHY LAMS S/ASPH	Y	2.81
4	2173.0 - 73.5	2.64	6.2	7.6	28.8	19.2	OIL	2.2	4.0	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
5	2174.0 - 75.0	3.75	7.1	11.0	22.2	15.4	OIL	2.4	6.9	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
6	2175.0 - 75.5	2.92	5.6	9.1	17.5	48.6	OIL	1.6	3.1	SD BRN VFG SHY LAMS S/ASPH	Y	2.63
7	2176.0 - 77.0	8.92	11.9	14.5	12.4	23.9	OIL	1.8	9.3	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
8	2177.0 - 77.5	13.29	12.1	14.3	2.4	14.5	OIL	0.3	11.9	SD BRN VFG SHY LAMS S/ASPH	Y	2.64
9	2178.0 - 79.0	12.82	11.8	18.9	8.2	17.5	OIL	1.5	14.0	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
10	2179.0 - 79.5	14.21	13.6	16.6	10.8	23.2	OIL	1.8	11.0	SD BRN VFG S/ASPH	Y	2.60
11	2180.0 - 81.0	18.57	13.7	17.1	12.0	31.9	OIL	2.0	9.6	SD BRN VFG S/ASPH	Y	2.62
12	2181.0 - 82.0	23.02	13.1	17.0	10.4	33.2	OIL	1.8	9.6	SD BRN VFG S/ASPH	Y	2.60
13	2182.0 - 82.5	48.28	15.9	15.9	17.9	32.1	OIL	2.8	7.9	SD BRN VFG S/ASPH	Y	2.60
14	2183.0 - 83.5	13.61	11.5	12.4	10.5	28.7	OIL	1.3	7.6	SD BRN VFG S/ASPH	Y	2.69
15	2184.0 - 84.5	34.91	14.6	17.7	9.9	19.0	OIL	1.7	12.6	SD BRN VFG S/ASPH	Y	2.66
16	2185.0 - 86.0	11.41	11.0	11.6	20.4	23.2	OIL	2.4	8.9	SD BRN VFG S/ASPH	Y	2.64
17	2186.0 - 86.5	7.78	10.8	11.6	10.3	17.5	OIL	1.2	8.4	SD BRN VFG S/ASPH	Y	2.66
18	2187.0 - 88.0	13.98	12.2	14.5	8.0	24.0	OIL	1.2	9.8	SD BRN VFG S/ASPH (29.5 API)	Y	2.63
19	2188.0 - 88.5	16.21	12.8	14.8	7.8	28.2	OIL	1.2	9.5	SD BRN VFG S/ASPH	Y	2.62
20	2189.0 - 90.0	31.76	13.1	15.2	9.9	41.1	OIL	1.5	7.5	SD BRN VFG S/ASPH	Y	2.63
21	2190.0 - 90.5	35.08	13.7	15.6	2.9	24.3	OIL	0.4	14.5	SD BRN VFG SHY LAMS S/ASPH	Y	2.62
22	2191.0 - 92.0	61.02	14.6	13.6	6.0	26.7	OIL	0.8	12.0	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
23	2192.0 - 93.0	61.02	13.9	16.6	13.8	26.0	OIL	2.3	10.0	SD BRN VFG SHY LAMS S/ASPH	Y	2.59
24	2193.0 - 94.0	41.88	12.9	14.6	11.1	15.8	OIL	1.6	10.7	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
25	2194.0 - 94.5	51.86	10.7	15.4	11.9	14.8	OIL	1.8	11.3	SD BRN VFG SHY LAMS S/ASPH	Y	2.51
26	2195.0 - 95.5	2.42	12.7	9.2	17.6	23.0	OIL	1.6	5.5	SD BRN VFG SHY LAMS S/ASPH	Y	2.80
27	2196.0 - 97.0	1.35	11.0	16.2	15.9	21.3	OIL	2.6	10.2	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
28	2197.0 - 98.0	54.38	13.6	15.0	13.8	21.5	OIL	2.1	9.7	SD BRN VFG SHY LAMS S/ASPH	Y	2.60
29	2198.0 - 98.5	2.44	11.5	11.3	16.2	29.2	OIL	1.8	6.2	SD BRN VFG SHY LAMS S/ASPH	Y	2.66
30	2199.0 - 99.5	4.56	9.9	11.5	10.4	28.4	OIL	1.2	9.3	SD BRN VFG SHY LAMS S/ASPH	Y	2.61
0	2200.0 - 101.5									SHALE DK GRY	0	

Figure 8. NBCU 2-11 No.3 conventional core analysis.

grams of each core were placed in a six-ounce bottle containing 100 ml of distilled water and shaken on a rotary shaker at 110 rpm for two hours. Samples were immediately withdrawn for analyses of the microbial content. Numbers of aerobic heterotrophs and aerobic oil-degrading microorganisms were determined using Bacto-Plate Count Agar and oil agar, respectively, on samples from all three wells. Numbers of anaerobic heterotrophs and anaerobic oil-degrading microorganisms were determined using Bacto-Plate Count Agar and oil agar, respectively, on samples from wells 2-13 No. 2 and 2-11 No.3.

The bottles were allowed to remain quiescent for 12 hours in a refrigerator and prior to inorganic chemical analyses suspended matter was removed by filtration through a 0.45 μ millipore filter. The methods employed for the inorganic analyses were as follows.

Orthophosphate was determined using the Ascorbic Acid Reduction Method as given in the Standard Methods for the Examination of Water and Wastewater[6].

Nitrate-nitrogen was determined using the Cadmium Reduction Method as given in the Standard Methods for the Examination of Water and Wastewater[6].

Electron microscope observations were made using a Leica Stereoscan Model #360. Specimens of core samples were mounted on metal stubs, put in the vacuum chamber of a Polaron Model # E 5100 Sputter Coater, and the air atmosphere replaced with argon. The specimens were sputter coated with gold-palladium (60% gold, 40% palladium).

(2) Results

The concentration of nitrate ions and orthophosphate ions in five sections of core from each of the three newly drilled wells is given in Table 4. 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 section of the core samples from wells 2-5 No. 2, 2-13 No. 2, and 2-11 No. 3, respectively. It should be remembered that phosphate can react with constituents (*e.g.* calcium ions) in the formation and, consequently, the data only reflect that orthophosphate that is in solution. The results, however, clearly demonstrate that the nutrients are being widely distributed in the oil-bearing formation.

As shown in Table 5 microorganisms were present in all sections of cores from all three newly drilled wells and, as may be observed, the numbers vary as would be expected, but the larger numbers in some samples suggest that they probably have been proliferating. As may be noted both 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 gave no evidence of microbial cells. Scattered microbial cells as illustrated in Figure 9), were observed in a number of samples from all three wells and in some cases (see Figures 10, 11, and 12) large clusters of cells were observed indicating that the added nutrients are having the desired effect of promoting microbial growth in the reservoir.

Table 4. Concentration of Nitrate and Orthophosphate Ions in Sections of Cores From Three Newly Drilled Wells.

WELL NO.	CORE SECTIONS (No.)	DEPTH m	DEPTH ft	NITRATE (ppm)	PHOSPHATE (ppm)
2-5 No. 2	3	675.7	2217	0.04	<0.01
2-5 No. 2	5	674.8	2214	0.03	0.10
2-5 No. 2	11	673.0	2208	0.02	0.17
2-5 No. 2	12	672.1	2205	0.09	0.24
2-5 No. 2	15	669.0	2195	<0.01	<0.01
2-13 No. 2	4	671.5	2203	0.02	<0.01
2-13 No. 2	6	670.6	2200	0.03	<0.01
2-13 No. 2	11	669.6	2197	0.04	<0.01
2-13 No. 2	13	667.5	2190	<0.01	<0.01
2-13 No. 2	15	665.7	2184	<0.01	<0.01
2-11 No. 3	3	670.0	2198	0.04	0.05
2-11 No. 3	7	666.9	2188	0.08	<0.01
2-11 No. 3	8	666.3	2186	0.02	<0.01
2-11 No. 3	10	665.1	2182	0.02	<0.01
2-11 No. 3	14	663.5	2177	0.02	<0.01

Table 5. Numbers of Microorganisms in Sections of Cores From Three Newly Drilled Wells.

WELL NO.	CORE SECTION (No.)	DEPTH m	ft	HETEROTROPHS AEROBIC (No./g)	ANAEROBIC (No./g)	OIL-DEGRADING AEROBIC (No./g)	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

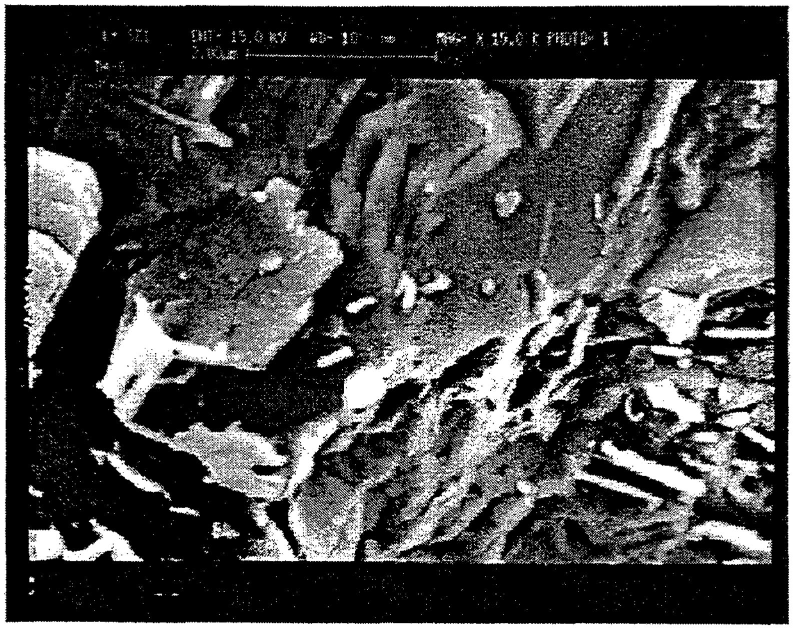

Figure 9. Electron micrograph of a sample of core from well 2-13 No.2, section 6. Note the scattered microbial cells.

Figure 10. Electron micrograph of a sample of core from well 2-11 No.3, section 3. Note the large number of microbial cells.

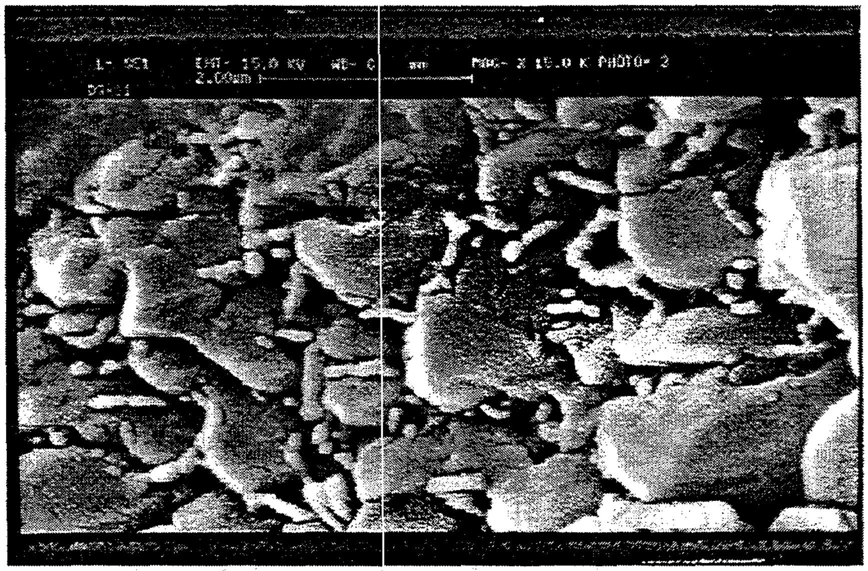

Figure 11. Electron micrograph of a sample of core from well 2-5 No.2, section 11. Note the large number of microbial cells.

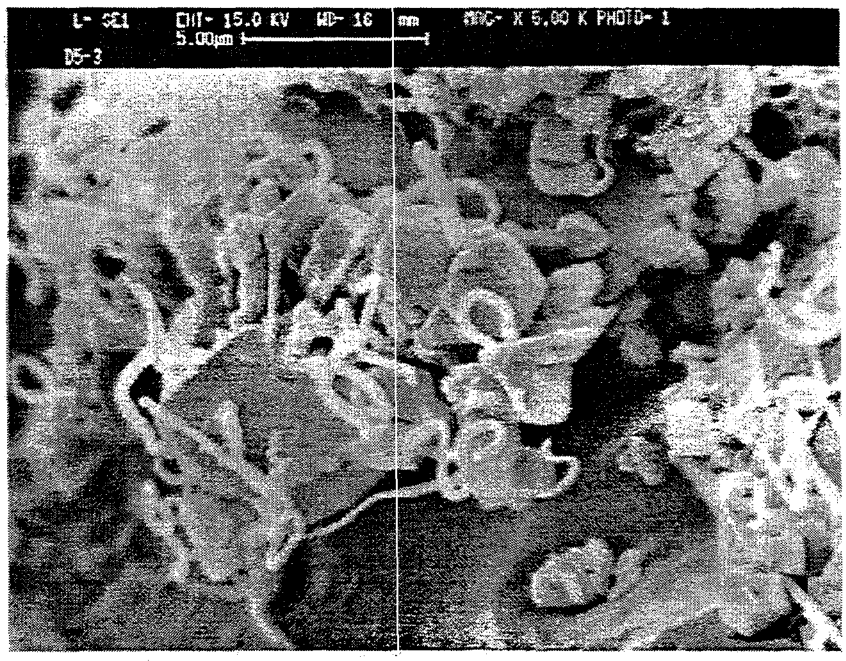

Figure 12. Electron micrograph of a sample of core from well 2-11 No.3, section 3. Note the large number of microbial cells.

c. <u>Geological Characterization of Core Samples</u>

The geological information gathered from the recovered core samples in Phase I, have been characterized geologically by thin section, Secondary Electron Imagery (S.E.I.), and x-ray diffraction analyzing methods (See Annual Report, 1995).

d. <u>Petrophysical Study of Core Samples</u>

The petrophysical properties of recovered core samples in Phase I have been previously reported (See Annual Report, 1995). The petrophysical properties of collected cores from the three newly wells drilled in Phase II are given in Table 6. In this table the lowest, the highest, and a median range is presented to show the intensity of heterogeneity of the reservoir formation.

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.

e. <u>Analysis of Injection and Production Fluids</u>

Fluids from both injector wells and producer wells in all patterns, were collected monthly in one and one-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, viscosity, 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. To date, 28-33 samples from each well have been collected and analyzed.

(1) Petrophysical analyses

The following characteristics of produced fluids from selected wells have been measured and representative values given in Table 7.

- Gas chromatography (GC) to determine the aliphatic profile of oil from producer wells in all patterns. [From these data it is hoped that evidence of oil from previously unswept areas of the reservoir will be found in the produced oil. This finding will help confirm that microbial growth in the reservoirs is indeed altering the sweep pattern in the reservoir.]
- Gravity (API) of oil (at room temperature) produced from selected wells in test and control patterns. [It is expected that the API gravity of produced oil will increase as new oil (lighter oil) is swept into producing wells. Generally speaking, lighter crude oil has been produced for years and the oil presently being swept from the reservoir is somewhat heavier than untapped oil. Information on gravity variation therefore could be used as supportive evidence of production of new oil due to microbial selective plugging. See Table 7.]

Table 6. 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	14.4	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

Table 7. Petrophysical Analysis of Selected Test and Control Wells in All Patterns.

Wells		Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
PATTERN 1						
Test Well 2-15 No. 1						
	Range	33-31	2.4-2.1	57-62	25-30	9.4-8.8
	Trend	down	down	up	up	down
Test Well 2-13 No. 1						
	Range	37-30	2.25-1.95	63-57	22-21	8.3-7.4
	Trend	down	down	down	down	down
Control Well 3-1 No. 1						
	Range	37-31	2.4-1.6	57-60	22.5-29	8.2-8
	Trend	down	down	up	up	down
PATTERN 2						
Test Well 34-7 No. 2						
	Range	31-32	2.6-2.4	62-57	25-17.5	8.4-7.9
	Trend	steady	down	down	down	down
Control Well 34-2 No. 1						
	Range	33-32	1.75-1.8	61-58	24.5-22	8.5-8
	Trend	steady	steady	down	down	down
PATTERN 3						
Test Wells 10-8 No. 1						
	Range	25-27.5	5.2-4	63-62	23-25	8.3-7.8
	Trend	up	down	steady	steady	down
Test Wells 11-4 No. 1						
	Range	34-26	1.7-4.5	63-60	17-27	8.2-7.7
	Trend	down	up	steady	up	down

Table 7 (Continued).

Control Well 3-3 No. 1		Gravity API	Viscosity cP	Surface Tension W-air dyne/cm	Interfacial Tension O-W dyne/cm	pH
	Range	27.5-30	3.4-2.2	62-60	27.5-22.5	7.9-8.6
	Trend	up	down	steady	down	up
PATTERN 4						
Test Well 2-11 No. 2						
	Range	34-32	1.8-2.4	61-60	25-22.5	7.8-8
	Trend	steady	up	steady	down	steady
Control Well 3-9 No. 1						
	Range	31-32	1.7-2.1	63-58	22.5-227	8-7.9
	Trend	steady	up	down	steady	steady

- Viscosity of oil (at reservoir temperature) produced from selected wells in test and control patterns. [It is expected that the viscosity of the produced oil will decrease as new oil (lighter oil) is swept into the producing wells. Generally speaking lighter oil has a lower viscosity (see Table 7).]
- Interfacial tension (IFT) for produced and separated oil-water system from selected wells in test and control patterns. [The production of surfactants by the microbial population may cause a reduction in the interfacial tension between the oil and the water phases and/or between water and oil and sand surface. Monitoring IFT in a producing oil-water system may lead to evidence of microbial activities in the reservoir (see Table 7).]
- Surface tension (ST) of air-water systems as in IFT. [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 samples from control wells or from historical data from the same well (see Table 7).]
- pH of produced water. [Monitoring the acidity of produced water from producing wells in test patterns and comparing it to produced water from control wells or historical data is only for the sake of determining if acids or other corrosive materials are being produced (particularly from molasses) and could be detrimental to the quality of oil or production facilities and eventually the environment (see Table 7).]

(2) Microbial populations

Production fluids are still being monitored for microbial content but to date no significant findings have been observed. While the data await final analyses, it should be emphasized 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 ions

Production fluids are still being monitored for chloride ions, hardness, nitrate ions, phosphate ions, potassium ions, sulfate ions, and sulfide ions.

No sulfide ions have been detected in the fluids from any of the production wells this year (limit of detection 0.02 ppm). No significant changes attributable to the MEOR process have been seen in the concentrations of chloride ions, hardness, potassium ions, or sulfate ions.

No nitrate ions have been found in the produced fluids from any of the wells, but as indicated in sections (3b2, pg 19) nitrate ions were found in some samples of the cores from all three of the newly drilled wells.

Phosphate ions have been found in the produced fluids from producer wells in three of the four test patterns (see Table 8) indicating that there is communication between the respective injector wells and these producer wells. This suggest that the nitrate ions are either being taken up by the microflora or are reacting with materials in the reservoir.

Table 8. Phosphate Ion Concentration in Produced Fluids From Producer Wells in Test Patterns.

Test Pattern	Well No.	Date	Phosphate Ion Concentration (ppm)
1	2-13 No.1	Feb. 1997	0.24
1	2-13 No. 1	Apr. 1997	0.98
1	2-13 No. 1	Aug. 1997	1.45
1	2-13 No. 1	Oct. 1997	trace
1	11-3 No.1	June 1997	1.32
2	34-15 No.2	June 1997	0.10
2	34-16 No.2	Oct. 1997	trace
3	11-6 No.1	June 1997	1.09
3	11-3 No.1	June 1997	1.32

(4) Gas composition

Increased gas production that has been noted in some wells could be the result of microbial activity or it could 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). Column 1 was a 20' x 1/8" aluminum column packed with 37.5% DC-200/500 on 80/100 mesh chromosorb P-AW. Column 2 was a 6' x 3/16"aluminum column packed with 60/80 mesh molecular sieve, 13x. The column temperature was 70 C and the injector temperature was 65 C. The carrier gas, helium, was employed at a flow rate of 35 ml per min (back pressure 40 psi). All analyses were performed on 50 µl samples. Standard curves were prepared for all gases used throughout these investigations by analyzing various amounts (25 µl to 100 µl) of authentic samples and averaging four replications. Identification of gases was achieved by comparison of the retention time of peaks on the chromatogram to the retention times of standard gases. Quantitation was accomplished by comparison of the area under the curve for a given gas to a standard curve prepared with a pure sample of that gas.

Several sets of samples have been analyzed this year but because of the limited amount of data, no conclusions can be drawn at this time. Continued analyses may help clarify the origin of the gas.

f. Criteria for Evaluating Success

The criteria under which the success of the project will be measured are as follows:

- Decrease in water:oil ratio (WOR)
- More sustainable production
- Proof of stimulation of indigenous microorganisms
- Better understanding of reservoir and reservoir formation as a microbial environment for the future methods of selecting reservoir candidates for MEOR.
- Increase in Productivity Index in producing wells, and decrease in injectivity of injection wells.
- Overall decrease in cost per barrel of oil produced.
- Increase in productive life of the reservoir which translates into lower residual oil in place.

Plots of production fluids rate and WOR versus time will show any sustained increase or decrease in oil production, and decrease/increase in water production. Microorganisms, as by-products of their metabolism, produce surfactants which cause a reduction in IFT and also may effect the wettability of the reservoir formation. They also will produce gases which may effect the acidity of the reservoir water and/or decrease the viscosity of reservoir oil. Plots of reservoir oil gravity versus time may present some indication of the integrity of reservoir oil under the MEOR process. Plots of injection pressure and volume of injected water in time will present an indication of the continuity of the operation and injectivity of the injection well. Finally, gas chromatographic data may detect changes in the aliphatic profile of the oil.

g. Performance of MEOR Process in All Patterns

The project was initiated in January of 1994 and is approximately 73% completed. 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 turned 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, is holding steady, or there has been a noticeable decrease in the rate of decline and the WOR is decreasing, holding steady, or there has been a noticeable 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 Natural Decline or Abandoned, except in one case where other comments were made (see Tables 9 and 10). The performance of 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. Production plots for the two wells, 34-7 No.2 and 34-2 No.1, are shown in Figures A5 and A18, respectively. Note that the 34-7 No.2 is also in Test Pattern 2 and showed some positive response prior to beginning nutrient injection in Control Pattern 2, but the response has recently been improving. The production declines on both wells have actually reversed and production is increasing.

Although gravity, viscosity, surface tension, interfacial tension, and pH of produced fluids from producer wells have been monitored, no conclusions concerning these parameters have been made.

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

The injection volume is declining despite an increase in injection pressure. This performance may be an indication of microbial permeability reduction near the wellbore (see Figure A22).

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

Injection pressure is increasing and injection volume is decreasing. This performance may be an indication of microbial permeability reduction near the wellbore (see Figure A23).

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

The injection volume is on a decline and there was a slight increase in injection pressure which may be an indication of microbial permeability reduction near the wellbore (see Figure A24).

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

This well's injection rate and pressure are very sensitive to production (or lack of) from the 2-11 No. 3. Injection pressure increased and the injection volume increased over the last year (see Figure A25).

Table 9. Performance of Wells in Test Patterns.

WELL NO.	PATTERN	RESPONSE to MEOR	REMARKS
2-11 No. 1	**1 and 4**	**Positive**	Approximately five months after beginning the nutrient injection, there was an appreciable increase in oil production and the rate of decline in oil production became considerably less, although WOR is slightly increasing. 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 January to September 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**	**Inconclusive**	While this well cannot be considered as exhibiting a positive response, it should be noted that oil production increased from January 1997 to April 1997 and has remained steady since that time. WOR is generally increasing.
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 has fluctuated and is currently increasing.
34-7 No.2	**2**	**Positive**	Last year has shown an increasing trend in oil production and WOR has been declining. Shared with Control Pattern 2.
34-16 No. 2	**2**	**None**	Oil production demonstrated a natural decline until March 1996 after which time production decline seems to have decreased.
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 is increasing. Shared with Control Pattern 3.

Table 9. (Continued).

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.
34-10 No. 1	2	**Inconclusive**	Oil production has continued to decline however, since September 1997 there has been an increase and WOR has declined. Shared with Control Pattern 2.
10-8 No. 1	3	**None**	This well has had mechanical problems. While oil production has not shown a positive response, there are indications (aliphatic profile and petrophysical properties) that there has been a change in the characteristics of the produced oil suggesting new oil is being recovered. WOR is holding steady.
11-6 No. 1	3	**Positive**	This well has had mechanical problems. Approximately 15 months after beginning the nutrient injection, the oil production rate increased and subsequently held steady. WOR is holding steady.
11-4 No. 1	3	**None**	This well has continued its natural decline. WOR is slightly increasing.
2-11 No. 2	4	**Positive**	Approximately 13 months after beginning the nutrient injection, oil production increased until January 1997 when well 2-11 No. 3 began production and production from well 2-11 No.2 began to decline. After well 2-11 No. 3 was shut-in in August 1997 oil production stopped its decline. WOR continues to increase.
2-3 No. 1	4	**Inconclusive**	This well has shown indications of a positive response but oil production has not been consistently above the projected amount to be considered positive at this time. Approximately 24 months after beginning the nutrient injection, WOR began to drop sharply. This well is shared with Control Pattern 1.

Table 9. (Continued).

2-5 No. 1	4	**None**	This well continued on its natural decline until January 1997 when production fell dramatically due to the production from newly drilled wells 2-5 No. 2 and 2-11 No. 3. WOR continues to increase. This well is a shared well with Control Patterns 1 and 4.

Table 10. Performance of Wells in Control Patterns.

WELL NO.	PATTERN	STATUS	REMARKS
35-13 No. 1	**1**	**Natural Decline**	Oil production rate continuously decreasing and WOR continuously increasing.
35-14 No. 1	**1**	**Abandoned**	Due to uneconomical production rate
3-1 No. 1	**1, 3 and 4**	**Natural Decline**	This well has continued its natural decline. About August, 1997 the 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**	**Increase in Oil Production, Recently**	This well was exhibiting a natural decline until July 1997 at which time oil production began to increase appreciably possibly due to increased injection volume and nutrient injection into 34-7 No. 1. Also phosphate ions were detected in the production fluids from this well in October 1997. WOR has recently begun to decline.
34-6 No. 1	**2**	**Abandoned**	Due to uneconomical production rate
3-1 No. 2	**3 and 4**	**Positive Response**	The Positive Response in oil production is due to increase in water injection, not MEOR. WOR fluctuating 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 is generally increasing.
3-9 No. 1	**4**	**Natural Decline**	Oil production rate continuously decreasing and WOR continuously increasing.

h. 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 Dec.1997 is given in Figure 13 . During the period May 1994 (when the first project wells were placed on production) thru Dec.1997 total oil production was 58,850 m^3 (370,159 bbls). Based on projections derived for the period of Jan.1992-April 1994, oil production from May 1994-Dec. 1997 should have been only 41,890 m^3 (263,484 bbls). Of this 16,960 m^3 (106,675 bbls) of incremental oil produced, 9,007 m^3 (56,653 bbls) were from production of the five newly drilled wells, thus leaving a total of 7953 m^3 (50,022 bbls) of oil attributable to the MEOR treatment.

Further, calculations based on production from Jan. 1992 thru April 1994 indicate that the field would reach its economic limit of 238 m^3 (1500 bbls) of oil per month in 60 months (from 1/1/98). Based on the current oil production rate the remaining economic life of the field is 78 months. Thus, economic production would last 18 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 43,700 m^3 (275 MBO).

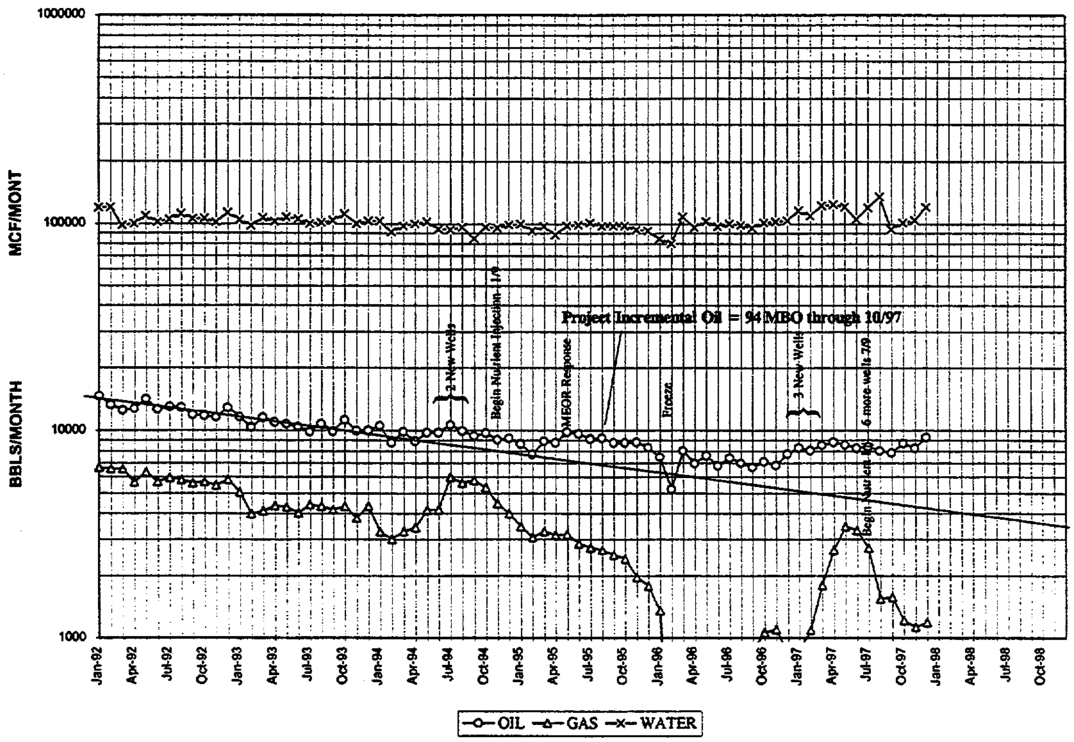

Figure 13. Total production from North Blowhorn Creek Oil Field.

SUMMARY AND CONCLUSIONS

The wide distribution of injected nutrients throughout the reservoir has been documented on the basis of (1) finding phosphate ions in the produced fluids from five producer wells in three of the four test patterns, (2) the presence of nitrate ions in core samples from all three of the newly drilled wells, and (3) the presence of phosphate ions in core samples from two of the three newly drilled wells.

The finding of large numbers of microorganisms in some sections of the cores from the three newly drilled wells indicates that microorganisms in the reservoir are proliferating.

Some producing wells have exhibited an increase in gas production during the year. Whether this increase in gas production is due to the fact that a greater portion of the produced fluid is coming from previously unswept areas of the reservoir or to microbial production is not known at present. The composition of the produced gases is now being monitored.

Performance of producing wells in all test patterns continues to be monitored. Of the 15 producing wells in the four original test patterns, seven have exhibited a positive response to the injection of nutrients into test injector wells. Four wells in these test patterns have failed to respond positively and the performance of four wells is characterized as inconclusive in regard to their response to the nutrient injection. Two of the producing wells in control patterns have been abandoned as a result of uneconomical production and five wells have continued their natural decline in oil production. One well has shown a positive response but that was due to increased water injection in a nearby injector, not to the MEOR treatment.

With DOE's approval, the scope of the field demonstration was expanded in July 1997 to include six new test injector wells. Two of these wells were previously control injectors while the other four injectors were not included in the original program. Of interest has been 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, both wells have begun to show improved oil production.

Based on calculations, 7953 m^3 (50,022 bbls) of additional oil has been obtained (exclusive of the five new wells) as a result of the MEOR technology. This finding is made even more meaningful in light of the fact that for most of the time only four of the twenty injector wells in the field were being treated.

One additional expected outcome of the technology being demonstrated in this project is the prolongation of economical production from the field. From extrapolation of oil production data, the economical life of the field has been extended by 18 months, and considering that there are now ten injector wells rather than only four, the economic longevity of the field is expected to increase.

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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

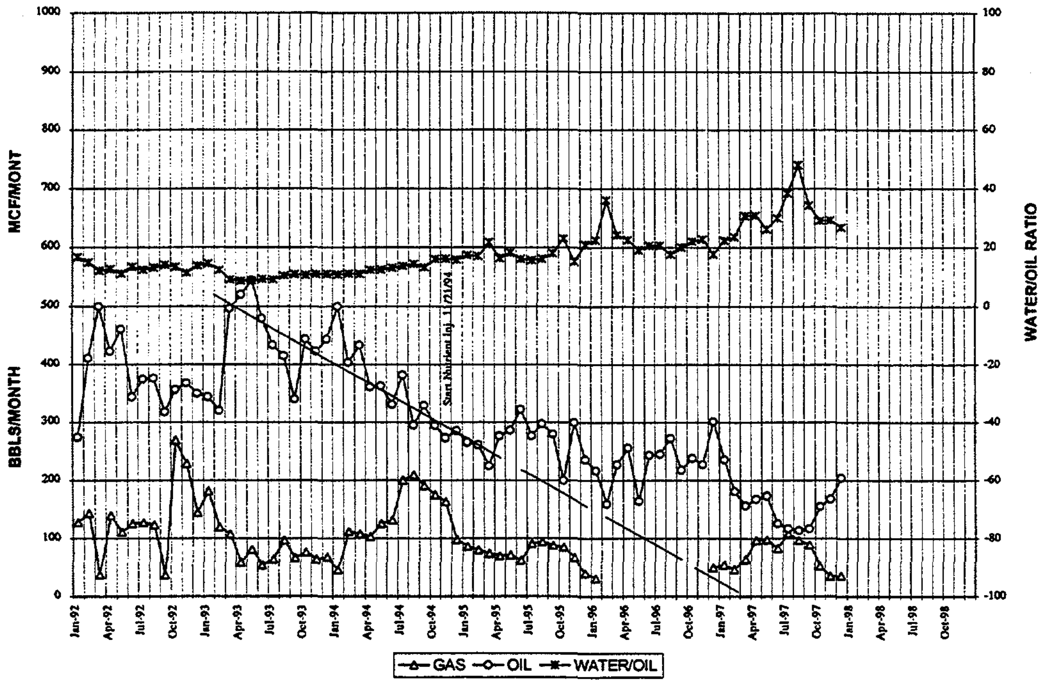

Figure A1. Performance of well 2-11 No.1 (test pattern 1).

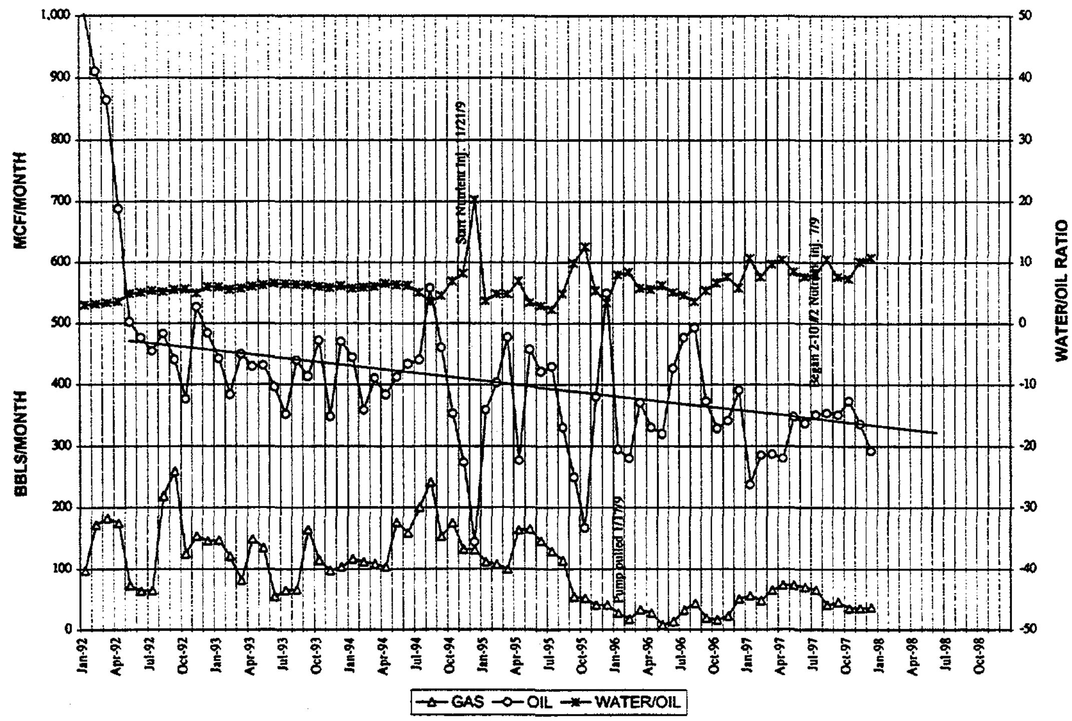

Figure A2. Performance of well 2-15 No.1 (test pattern 1).

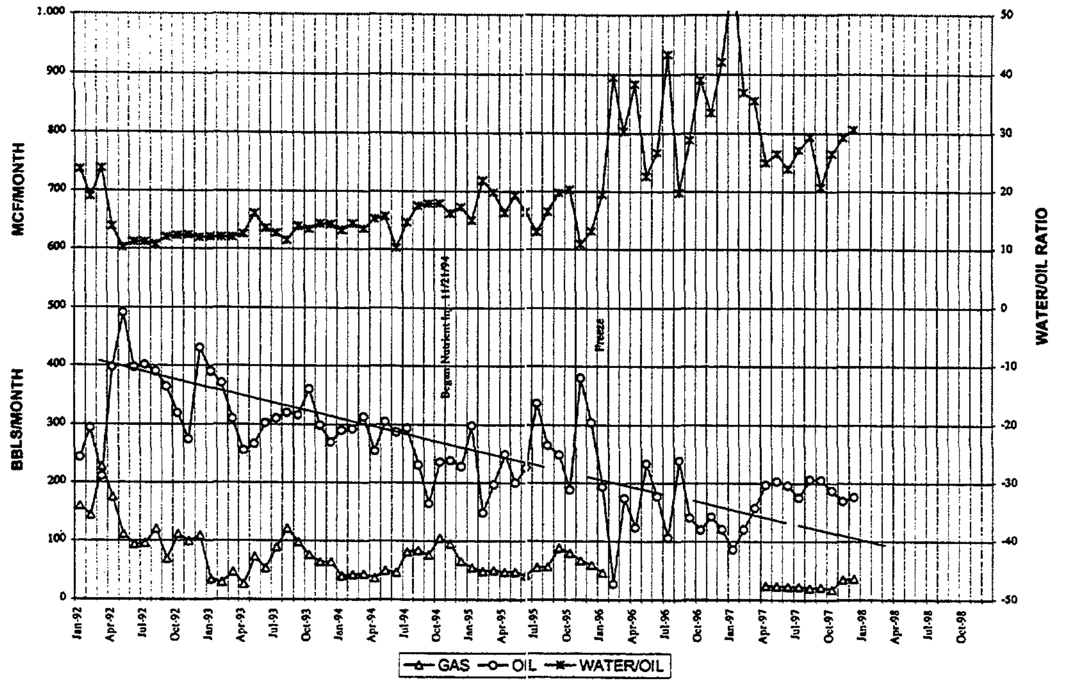

Figure A3. Performance of well 11-3 No.1 (test patterns 1,3).

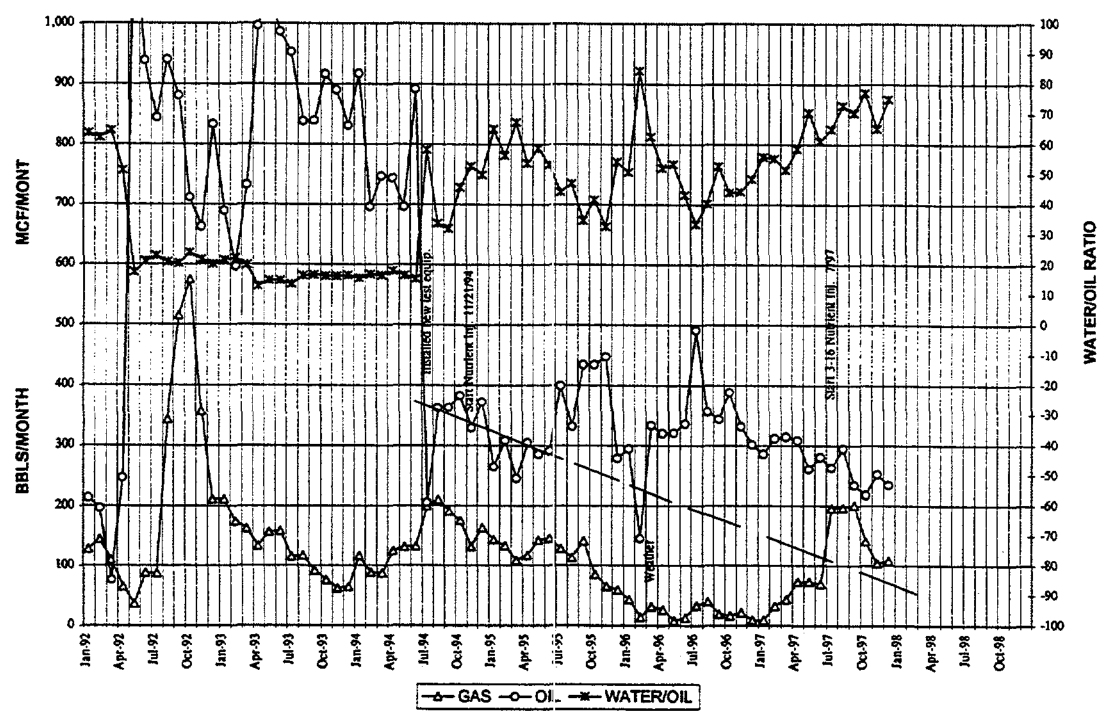

Figure A4. Performance of well 2-13 No.1 (test patterns 1,3).

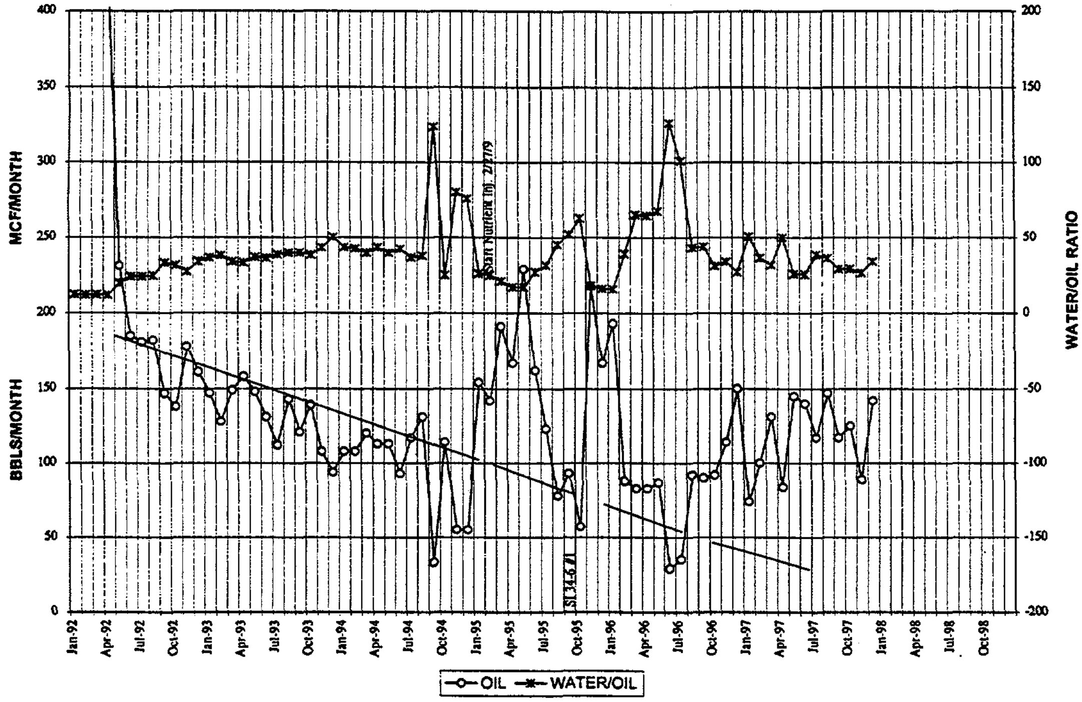

Figure A5. Performance of well 34-7 No.2 (test pattern 2 and control pattern 2).

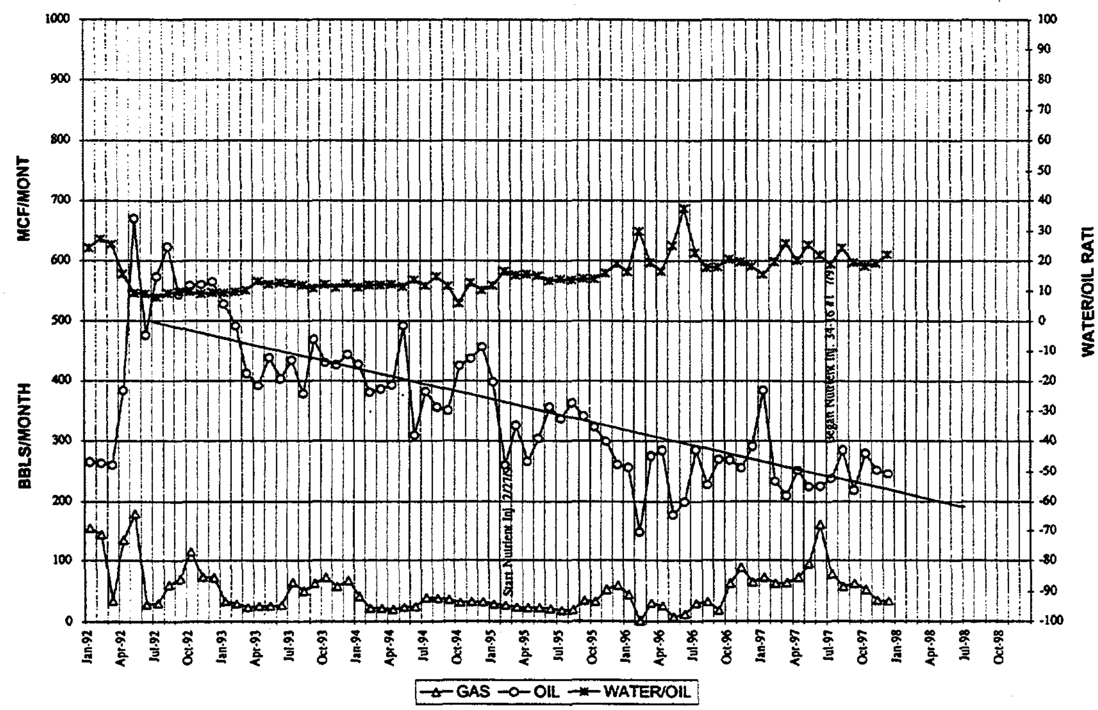

Figure A6. Performance of well 34-16 No.2 (test pattern 2).

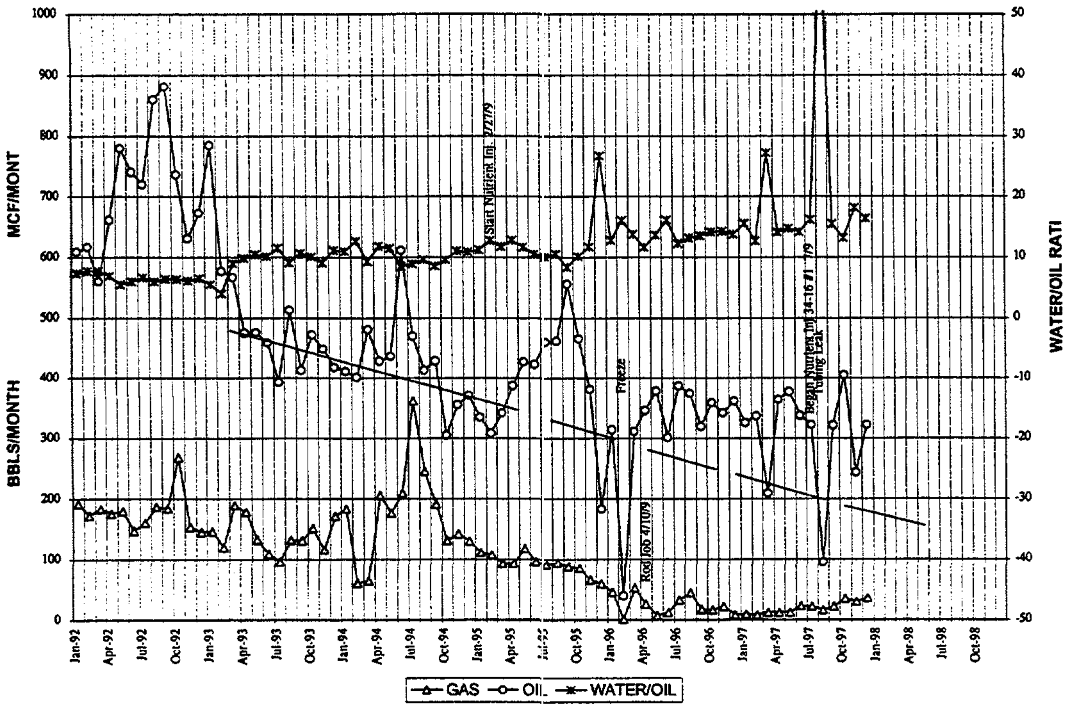

Figure A7. Performance of well 34-15 No.1 (test pattern 2 and control pattern 3).

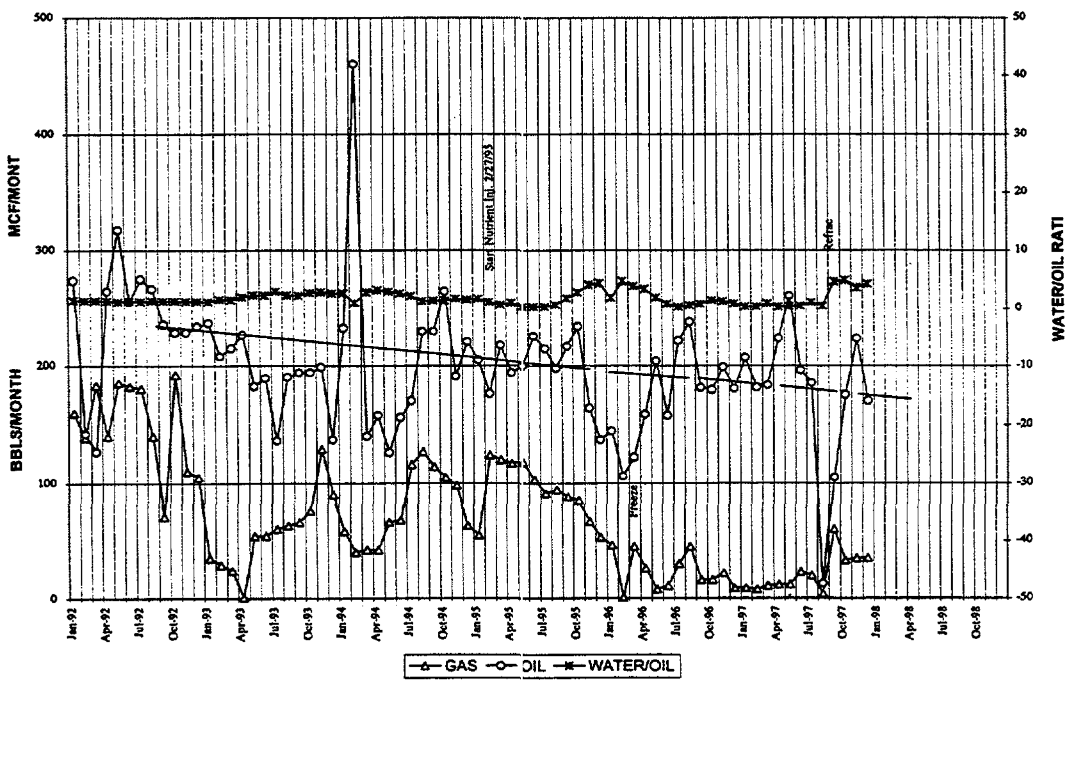

Figure A8. Performance of well 34-15 No.2 (test pattern 2 and control pattern 3).

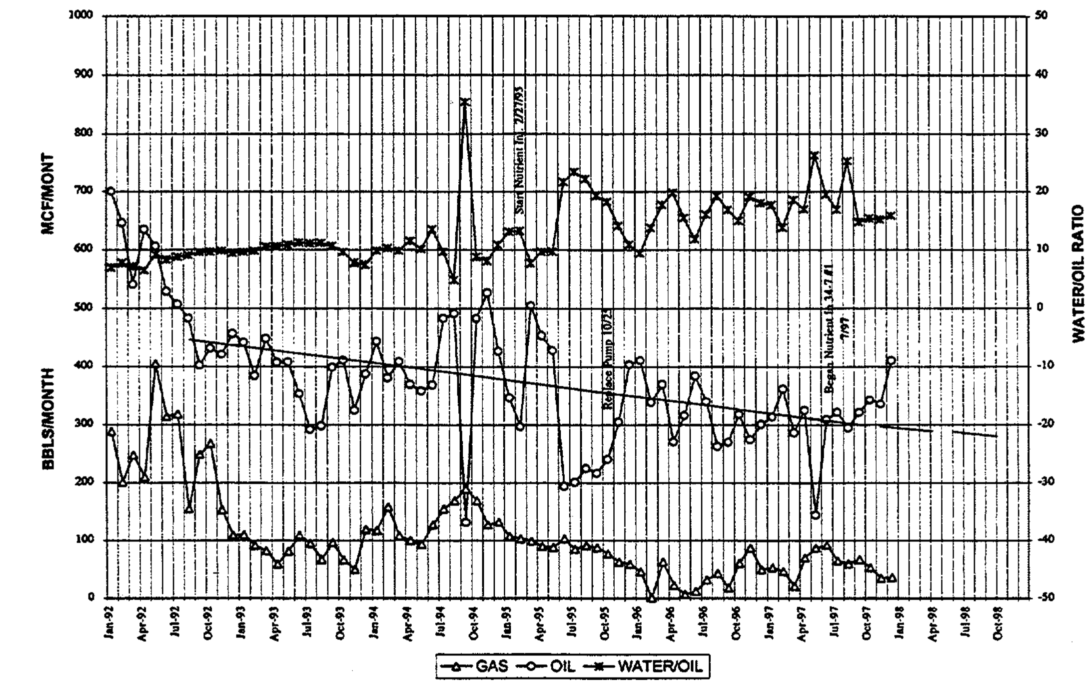

Figure A9. Performance of well 34-10 No.1 (test pattern 2 and control pattern 2).

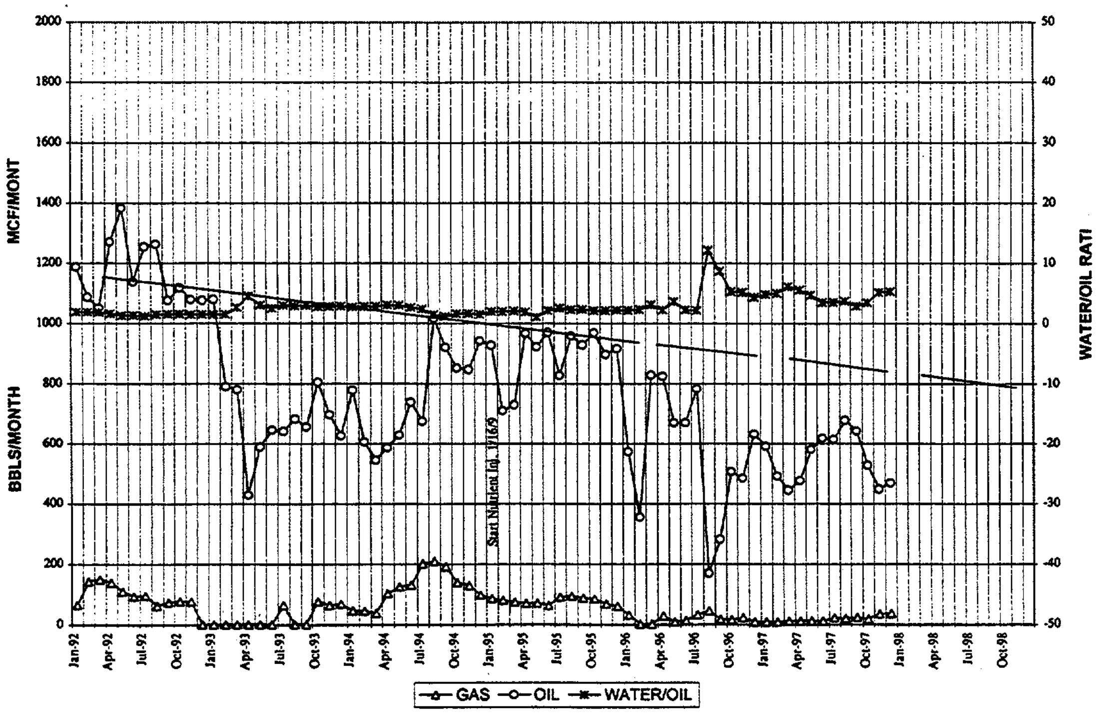

Figure A10. Performance of well 10-8 No.1 (test pattern 3).

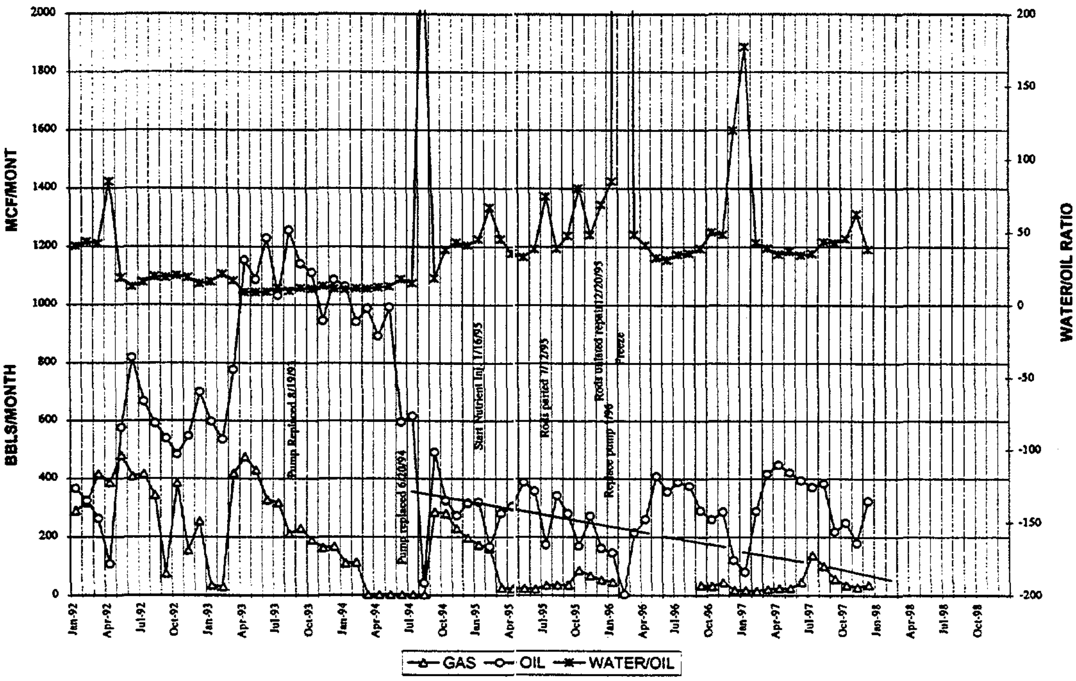

Figure A11. Performance of well 11-6 No.1 (test pattern 3).

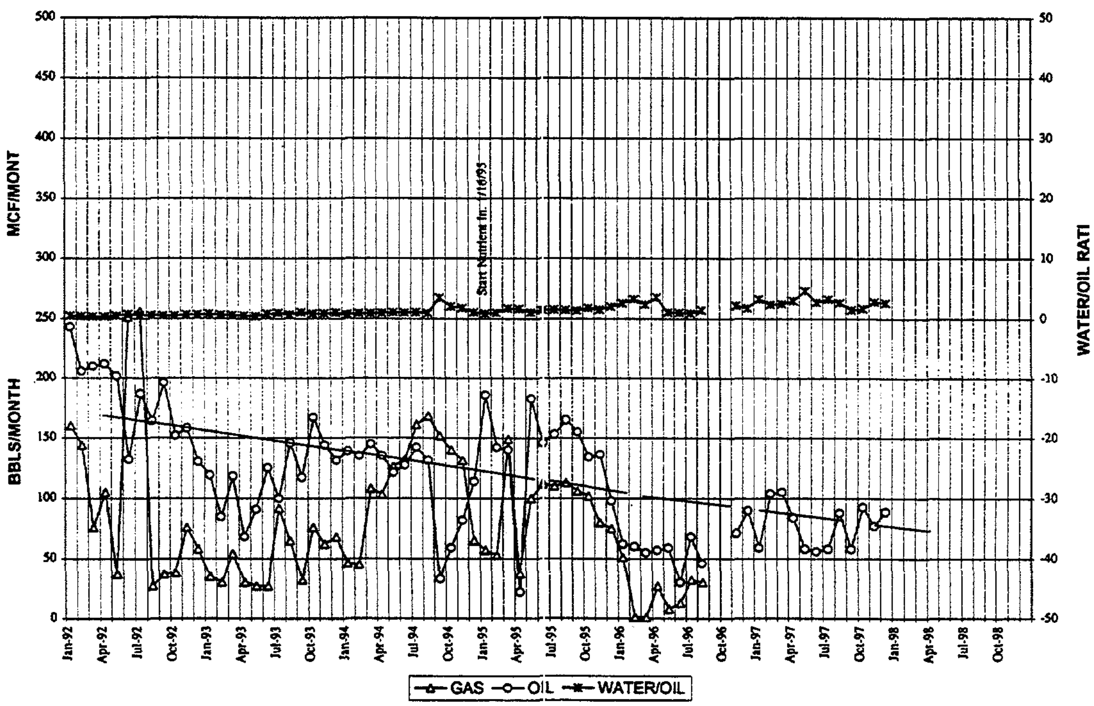

Figure A12. Performance of well 11-4 No.1 (test pattern 3).

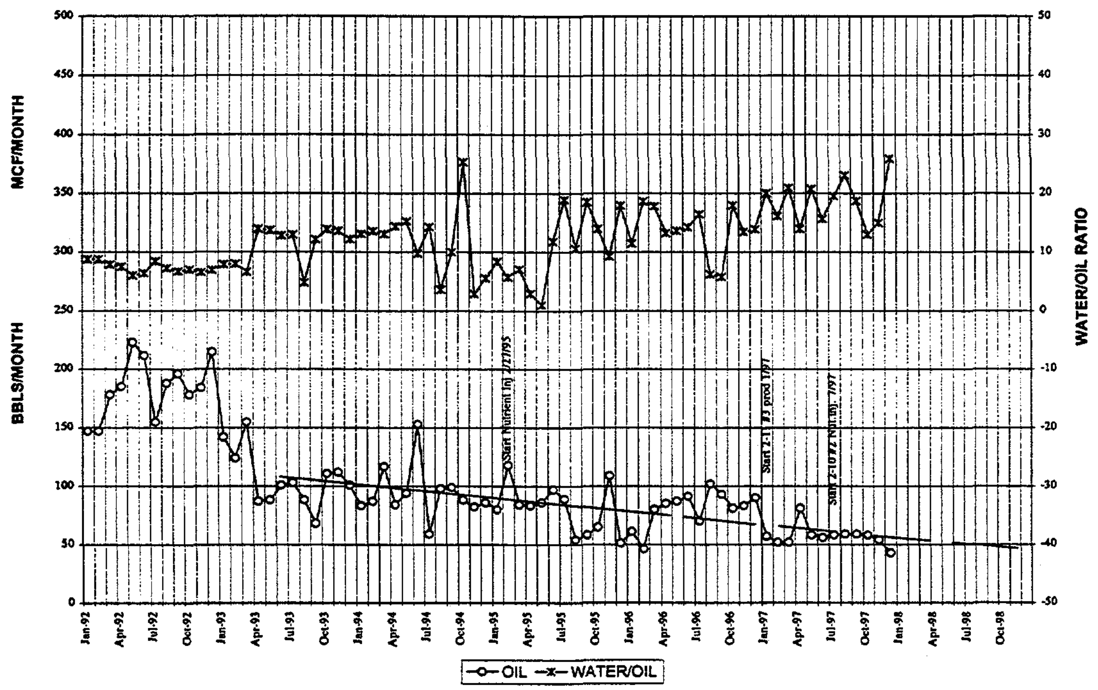

Figure A13. Performance of well 2-11 No.2 (test pattern 4).

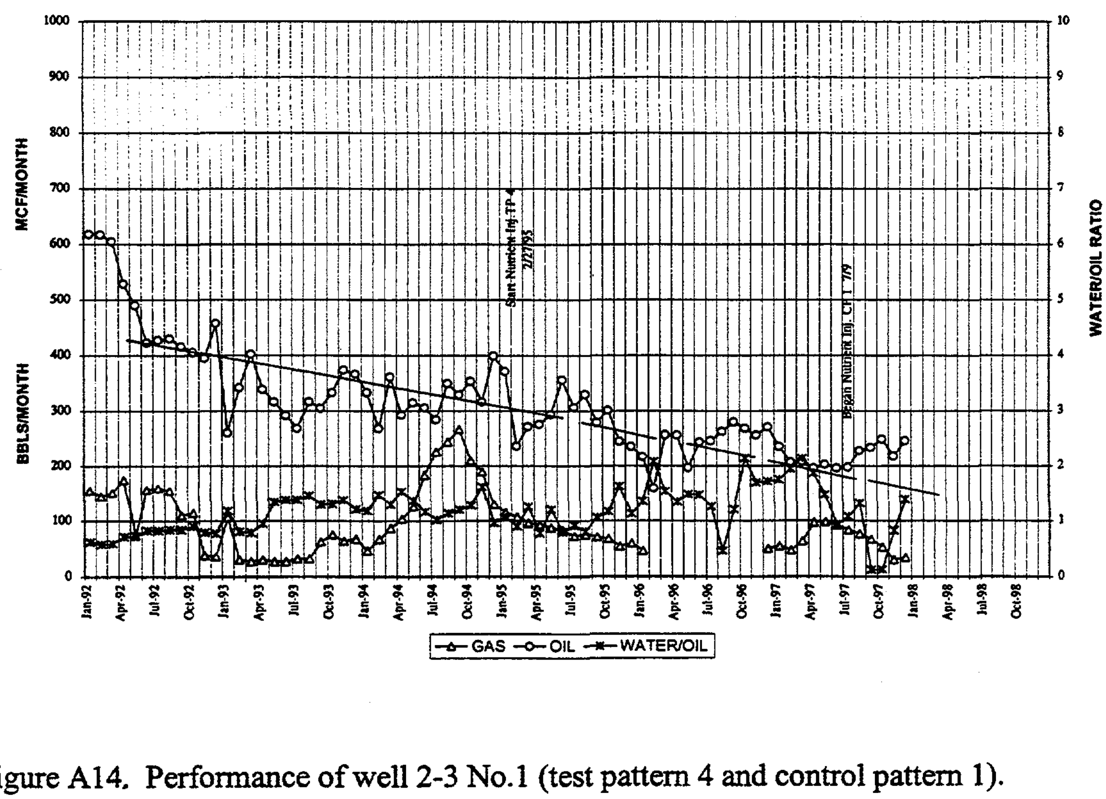

Figure A14. Performance of well 2-3 No.1 (test pattern 4 and control pattern 1).

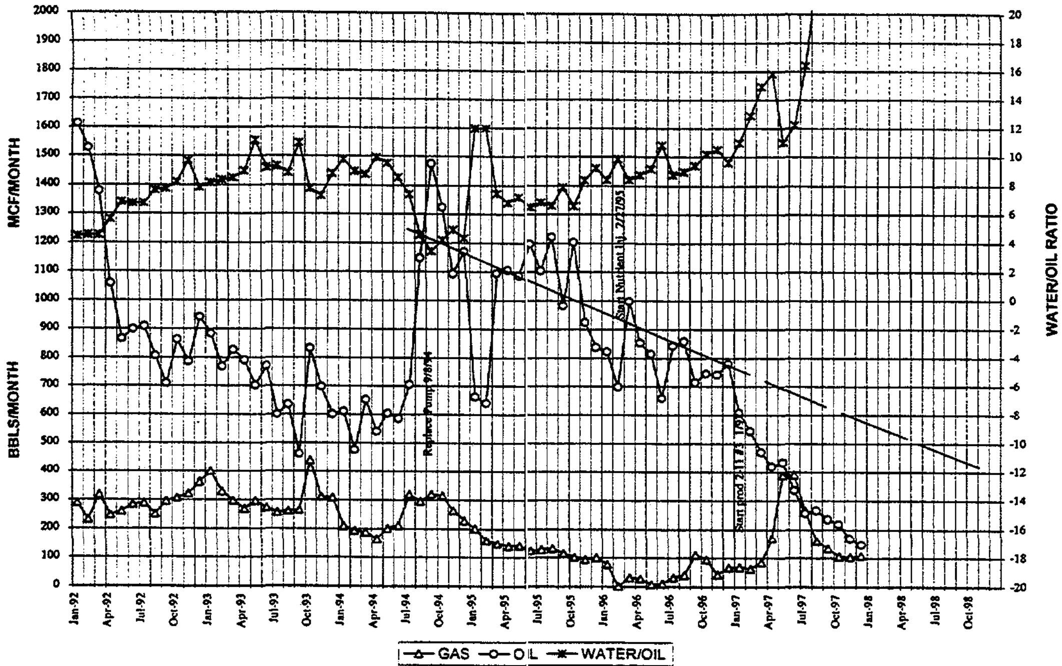

Figure A15. Performance of well 2-5 No.1 (test pattern 4 and control patterns 1,4).

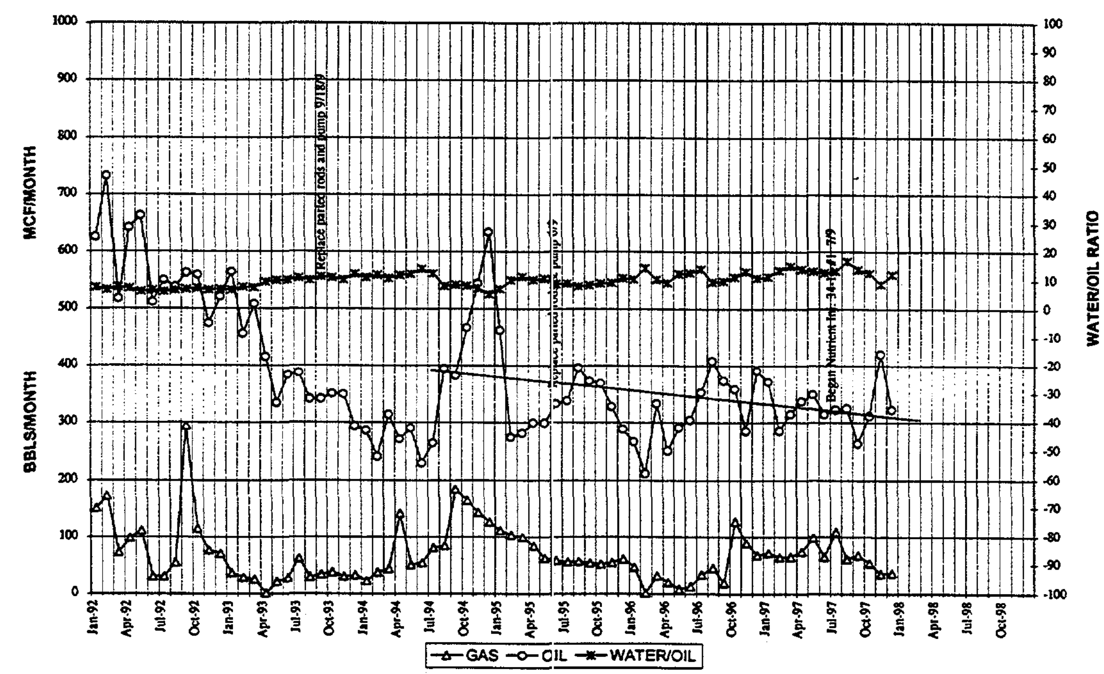

Figure A16. Performance of well 35-13 No.1 (control pattern 1).

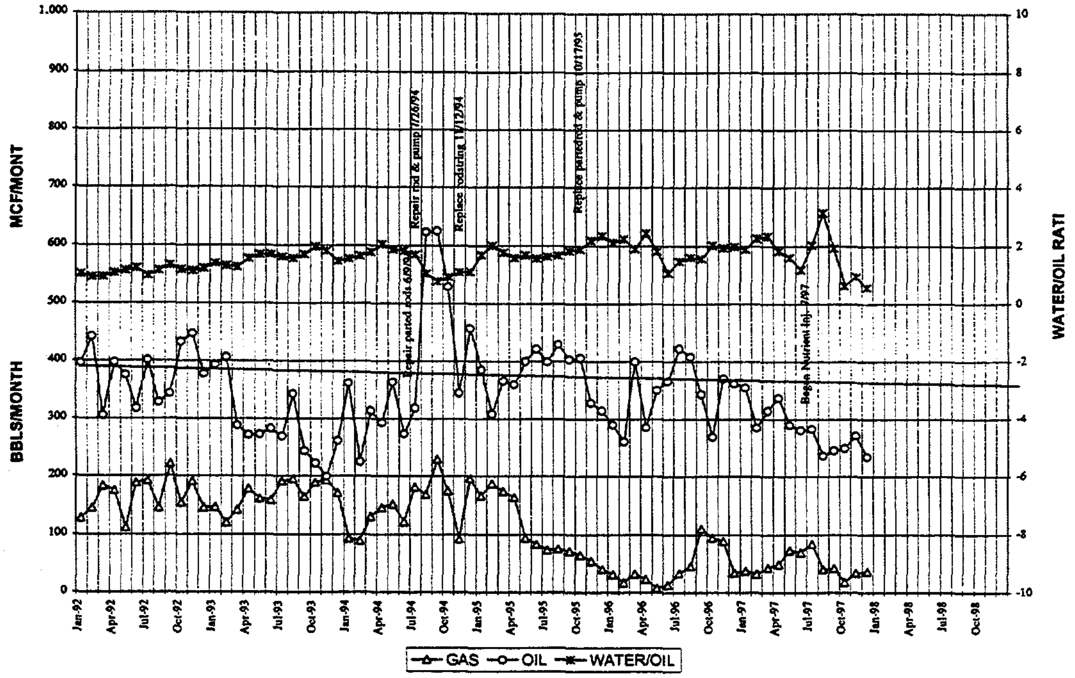

Figure A17. Performance of well 3-1 No.1 (control patterns 1,3,4).

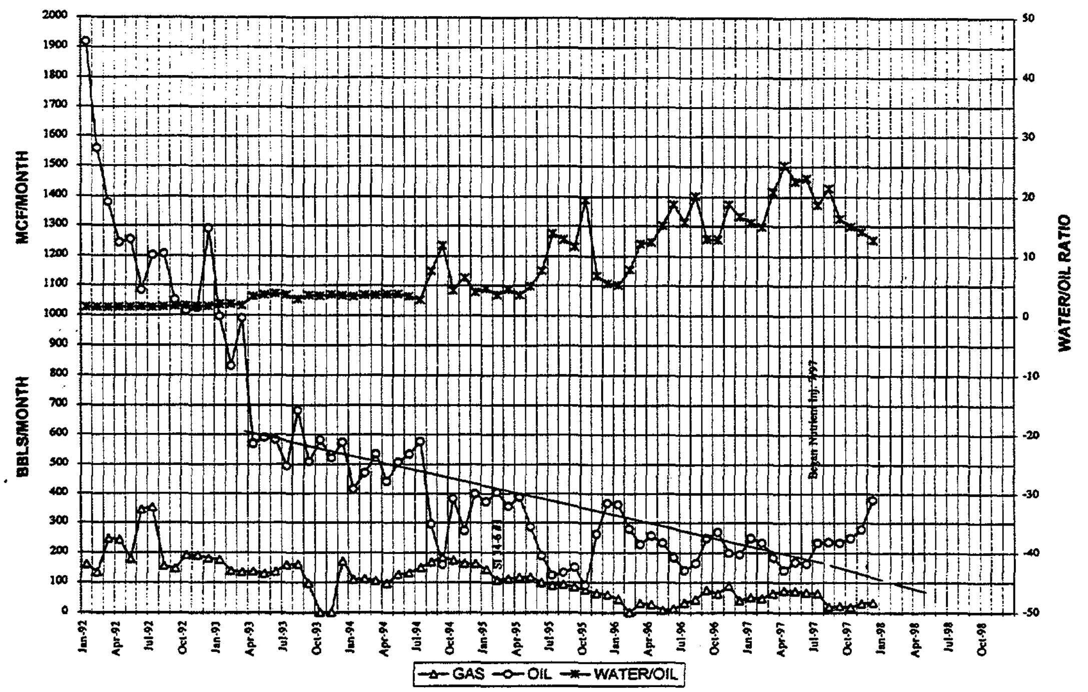

Figure A18. Performance of well 34-2 No.1 (control pattern 2).

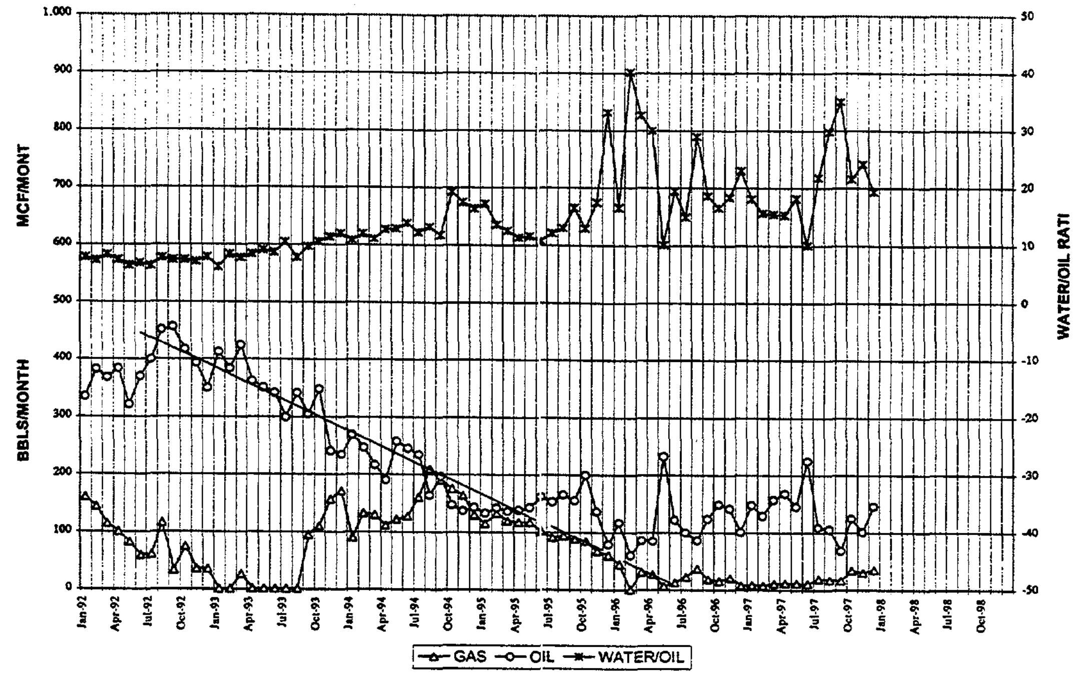

Figure A19. Performance of well 3-3 No.1 (control pattern 3).

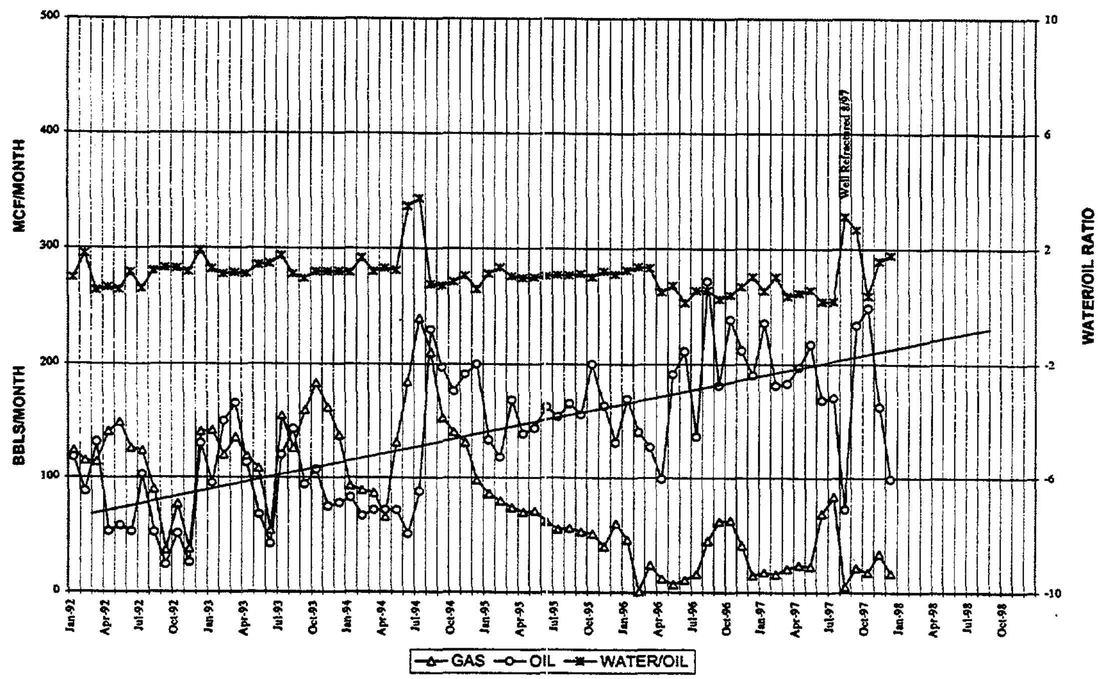

Figure A20. Performance of well 3-1 No.2 (control patterns 3,4).

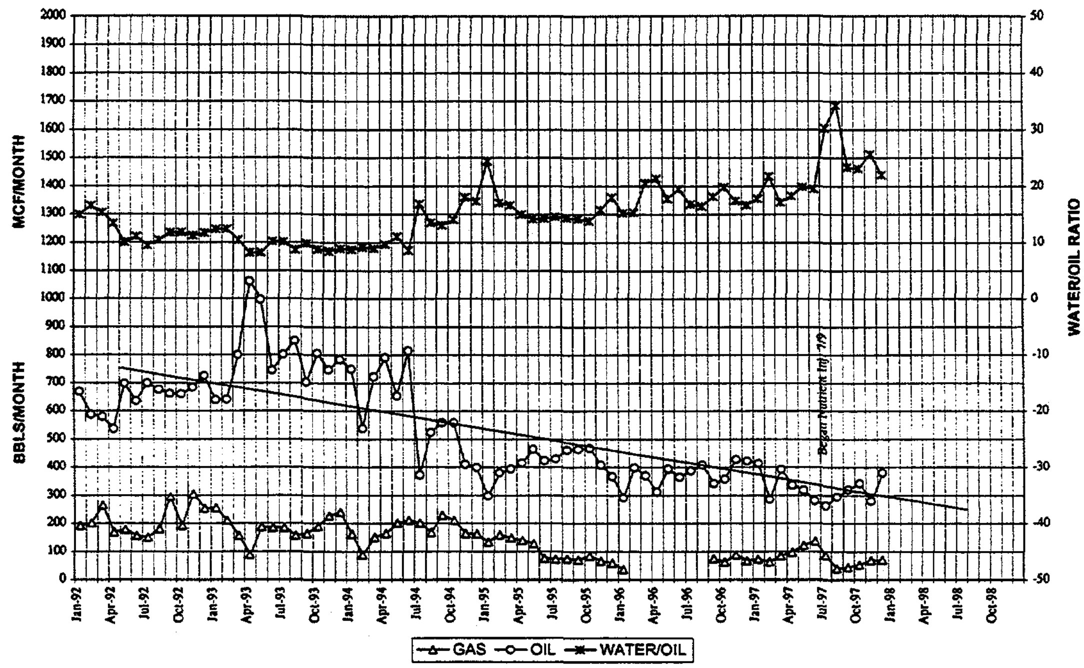

Figure A21. Performance of well 3-9 No.1 (control pattern 4).

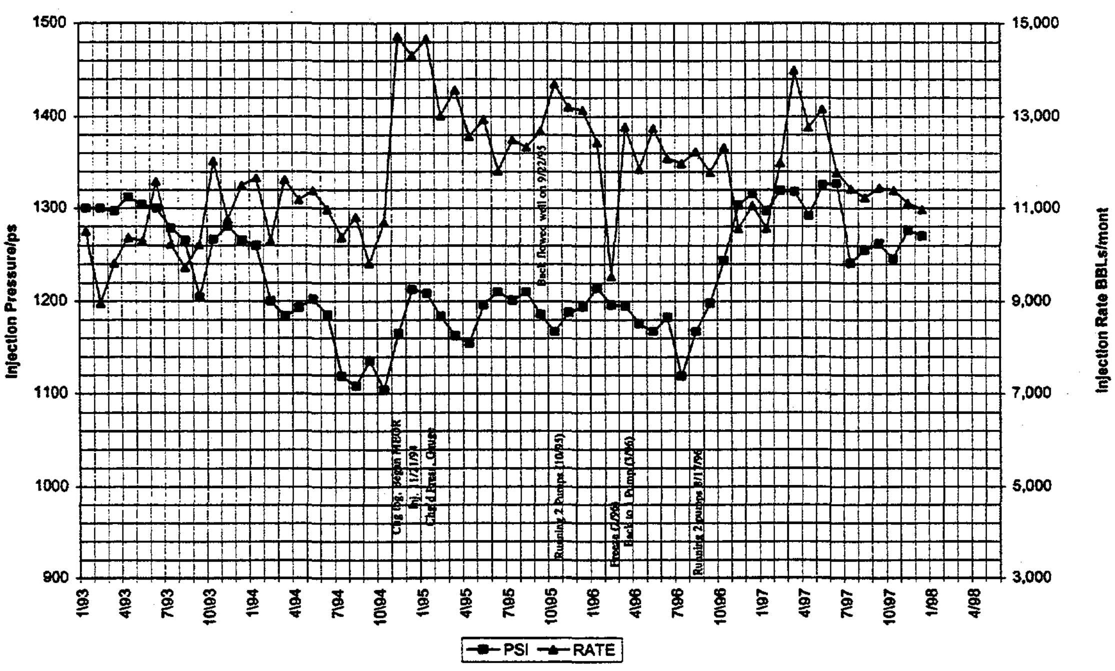

Figure A22. Performance of injection well 2-14 No.1 (test pattern 1).

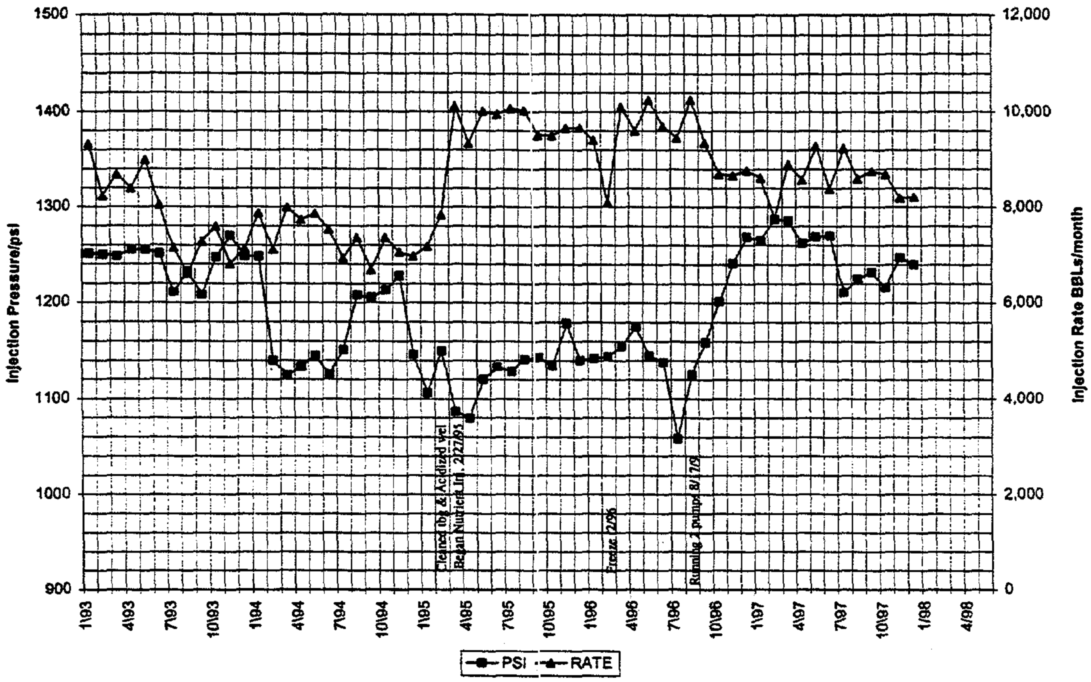

Figure A23. Performance of injection well 34-9 No.2 (test pattern 2).

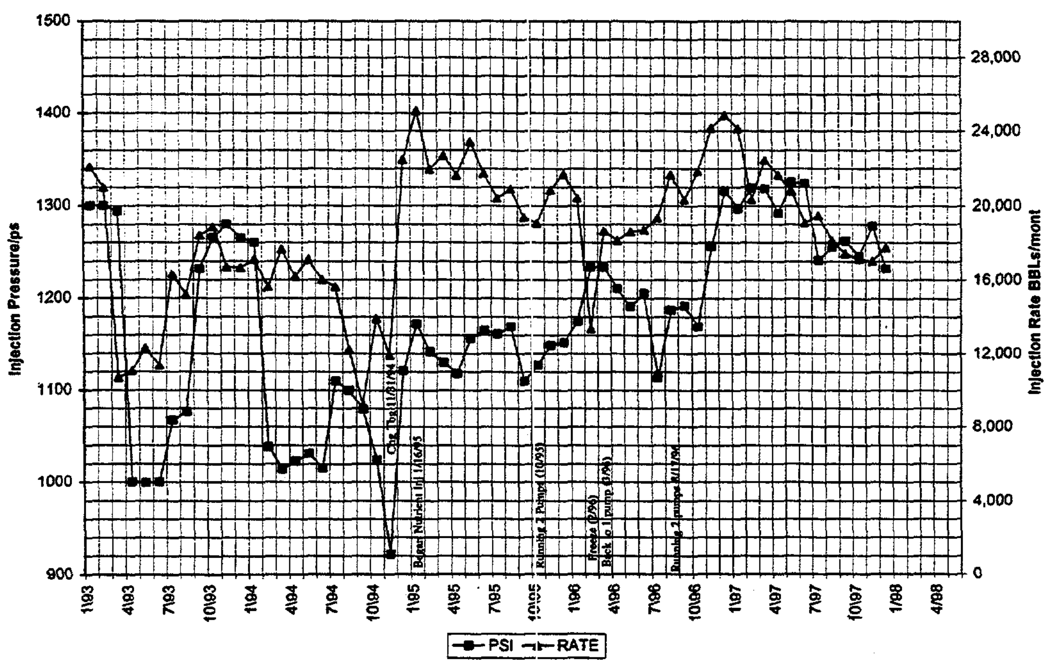

Figure A24. Performance of injection well 11-5 No.1 (test pattern 3).

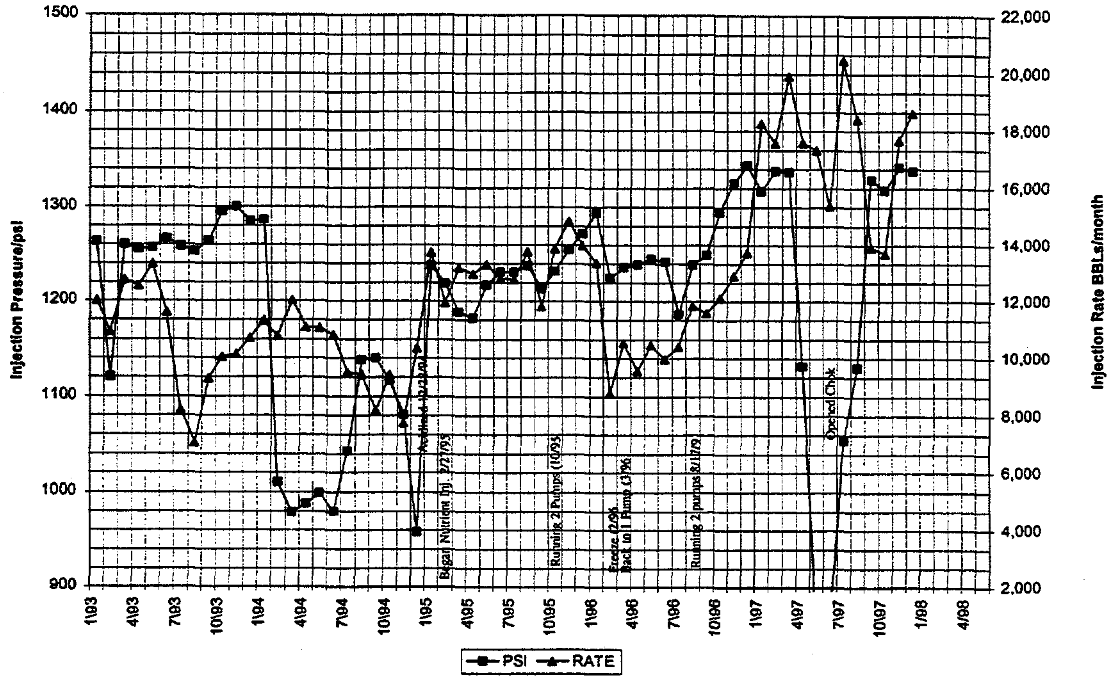

Figure A25. Performance of injection well 2-6 No.1 (test pattern 4).