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

Annual Report for the Period
January 1, 1995 to December 31, 1995

By
J. Stephens
L. Brown
A. Vadie

June 1996

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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Prepared for
U.S. Department of Energy
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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 thereby diverting flow to other areas of the reservoir and thus increase the efficiency of the waterflooding operation. This effect is to be accomplished by adding inorganic nutrients in the form of potassium nitrate and orthophosphate to the injection water. Work on the project is divided into three phases, Planning and Analysis (9 months), Implementation (45 months), and Technology Transfer (12 months). This report covers the second year of work on the project.

During the first year of the project, Phase I was completed and Phase II begun. Two wells were drilled in an area of the field where approximately twenty feet of Carter sand were found and appeared to contain oil bypassed by the existing waterflood. Cores from one well were obtained and used in laboratory core flood experiments. On the basis of the results, the schedule and amounts of nutrients to be employed in the field were formulated. 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 are receiving potassium nitrate and sodium dihydrogen phosphate while the other two are receiving 0.1% molasses in addition.

Early, but as yet inconclusive, results from producing wells in the first test pattern indicate increasing oil production and/or decreasing water-oil ratio.

Preliminary geological and petrophysical characterization of the reservoir has been made and baseline chemical and microbiological data have been obtained on all wells in all test and control patterns.

EXECUTIVE SUMMARY

This project is designed to demonstrate that a microbially enhanced oil recovery process, 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 waterflooding operations. 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, Technology Transfer (12 months). Phase I was completed and reported in the first annual report. The second annual report covers the findings in months 4-15 of Phase II.

During 1995, nutrient injection was begun in three additional test patterns. The nutrients consist of potassium nitrate, monosodium dihydrogen phosphate in all wells and molasses as a supplemental carbon source in two test patterns. The nutrients are injected in a prescribed sequence three days a week. To date, no injection problems have been encountered. The first two patterns to receive the nutrients have exhibited small declines in injection volumes at relatively constant injection pressure. The declines may be evidence of microbial growth near the well fracture faces. To date, seven wells in the first two test patterns have exhibited flattening of production decline, actual increases in production, and/or decreases in water-oil ratio. While the history is short and results are very preliminary, they are nevertheless very encouraging at this point in the project.

INTRODUCTION

Background on Microbial Enahnced Oil Recovery

The use of microorganisms to enhance oil recovery (MEOR) was first proposed by Beckmann in 1926 (1) but is was ZoBell that 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 increasing the effectiveness of waterflooding operations. 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 Second Annual Report will describe the work completed during, a twelve-month period of Phase II.

Phase I. Planning and Analyses

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.

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 orthophosphate.

Preliminary geological and petrophysical characterizations of the reservoir have been made. Baseline data on the inorganic constituents and microbial population have been obtained for fluids from all of the test and control wells. Petrophysical characteristics of selected wells in all test patterns have been determined also.

DISCUSSION

1. OBJECTIVE AND OVERALL PLAN OF WORK

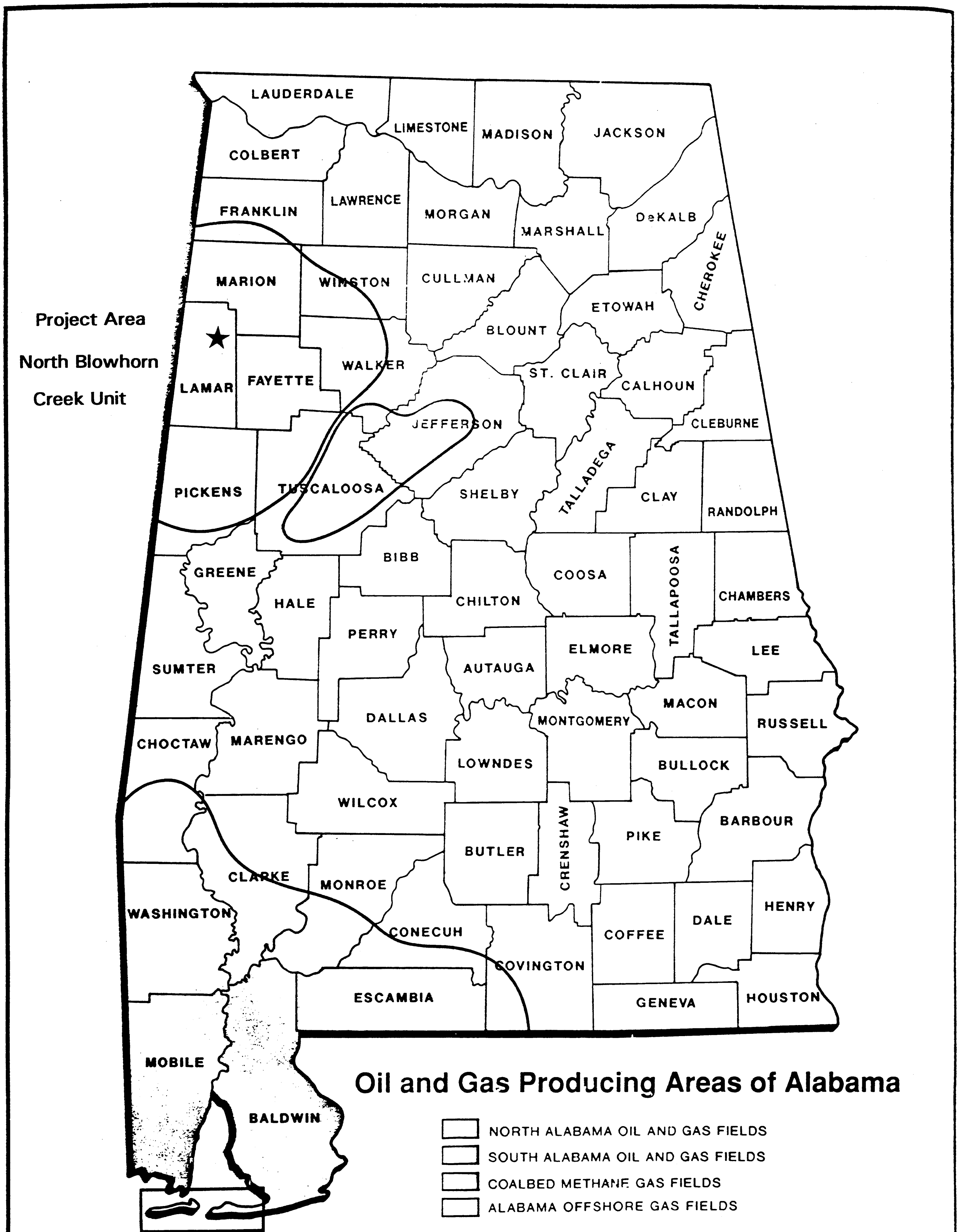
The objective of this work is to demonstrate the use of indigenous microbes as a method of profile control in waterfloods. It is expected that as the microbial population is induced to increase, the expanded biomass will selectively block the more permeable zones of the reservoir thereby forcing injection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

This increase in microbial population will be 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 zone of interest. The cores were subjected to special core analysis in order to arrive at the optimum nutrient formulation. 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.

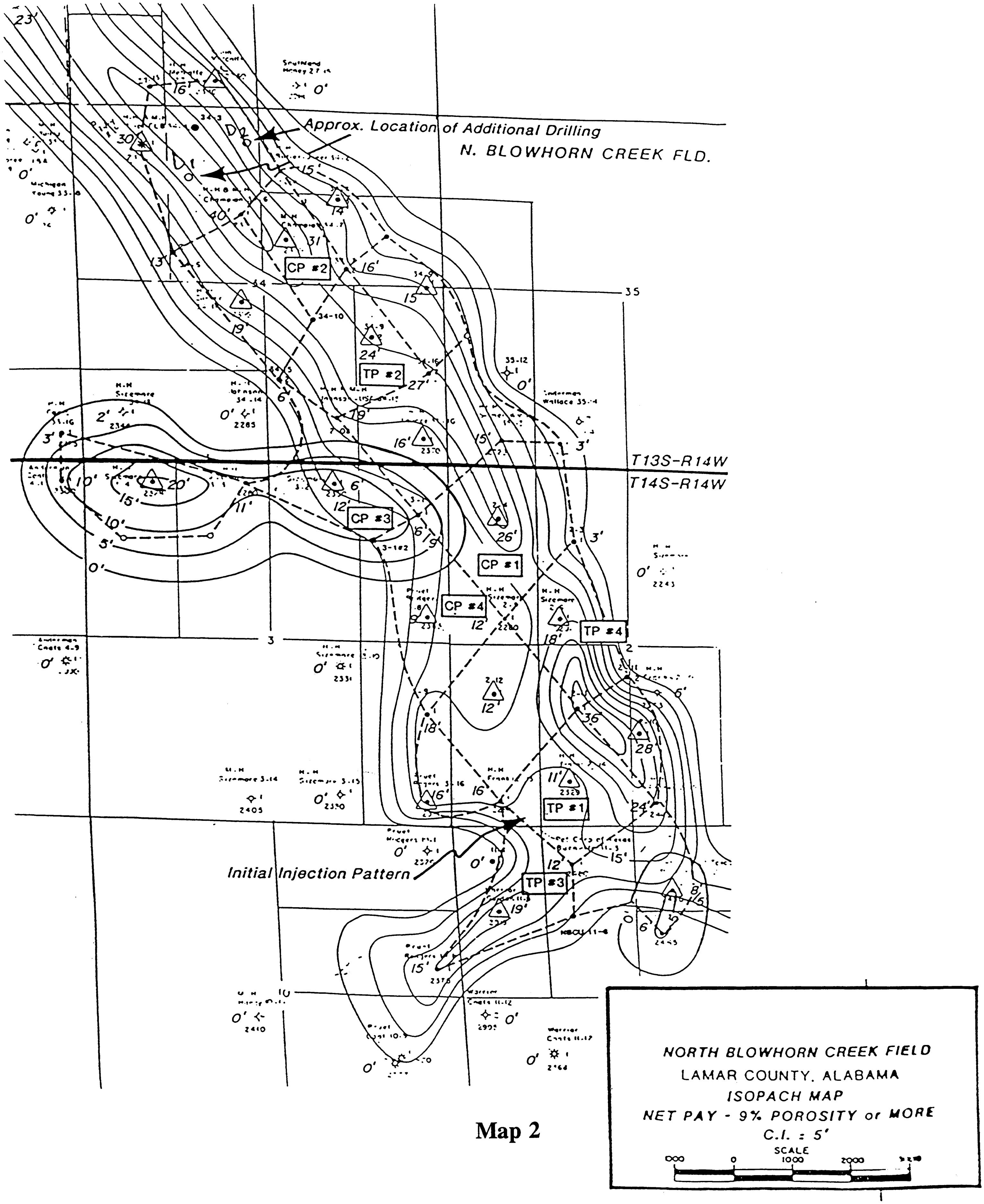
One expected outcome of this new technology will be a prolongation of economical waterflooding operations, i.e. economical oil recovery should continue for much longer periods in areas of the reservoir subjected to this selective plugging technique.

2. DESCRIPTION OF OIL RESERVOIR FOR FIELD TRIAL

The North Blowhorn Creek Oil Unit (NBCU) is located in northwest Alabama about seventy-five miles west of Birmingham. 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 2300 feet. The field was discovered in 1979 and initially developed on 80 acre spacing. The field was unitized into a reservoir-wide unit in 1983 and in-fill drilled to 40 acre spacing. Waterflooding of the reservoir began in 1983. The initial oil in place in the reservoir was about 16 million barrels, of which 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 Back Warrior Basin. Oil production peaked at almost 3000 BOPD in 1985 and has since steadily declined. Currently there are 20 injection wells and 32 producing wells. Current production is about 290 BOPD, 60 MCFD and 3100 BWPD. The current water injection rate is about 4150 BWPD. About 10 MMBO will be left unrecovered if some method of enhanced recovery is not proven to be feasible.



Map 1: Project Area Geographical Locator Map


Approx. Location of Additional Drilling
N. BLOWHORN CREEK FLD.
CP #2
TP #2
CP #3
CP #1
CP #4
TP #4
TP #1
TP #3
T13S-R14W
T14S-R14W
Initial Injection Pattern
NORTH BLOWHORN CREEK FIELD
LAMAR COUNTY, ALABAMA
ISOPACH MAP
NET PAY - 9% POROSITY or MORE
C.I. = 5'
SCALE

Map 2

A tracer study was initiated on the first test pattern and to date the tracer has been detected in two of the four surrounding wells. It appears that it will require at least a year or longer before evidence of microbial growth in the reservoir can be detected. More details of the results of Phase I may be found in (6) and (7).

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 years Annual Report they will be repeated here for sake of completeness. The wells included in the patterns are as follows (See Map 2).

TP No.1

Injection-Production Pattern:

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

CP No.1 (Control Set)

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

TP No. 2

Injection-Production Pattern:

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

CP No. 2 (Control Set)

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

TP No. 3

Injection-Production Pattern:

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

CP No. 3 (Control Set)

Injection Well:	NBCU 3-2 No.1
Production Wells:	NBCU 3-3 No.1
	NBCU 3-1 No.1*
	NBCU 3-1 No. 2*
	NBCU 34-15 No.1*
	NBCU 34-15 No. 2*

TP No. 4

Injection-Production Pattern:

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

CP No. 4 (Control Set)

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

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

(2). Feeding regime

The first test injector well (NBCU 2-14 No.1) was initially injecting 480-500 barrels of water per day. Based on this rate of injection and the results obtained from the core flood experiments, it was decided to employ the addition of potassium nitrate at a concentration of 0.12% (w/v) and disodium hydrogen phosphate at a concentration of 0.03% (w/v). The nutrients are mixed in much higher concentrations on the skids (described in last year's report) and injected at such rates that the entire amount of injection water during a 24-hour period will contain the above designated concentrations. In order to neutralize the effect of an increased pH of the injection water due to the phosphate addition, two gallons of 10% HCl (v/v) were added to each tank of phosphate solution. Monosodium dihydrogen phosphate is now being employed in place of disodium hydrogen phosphate, thus obviating the need for adding the 10% HC1.

The following injection schedule has been formulated based upon a waterflood injection rate of 480-500 BWPD in injector well NBCU 2-14 No.1.

Monday -	Mix 200 lbs (4 bags) of potassium nitrate with 200 gals of water and pump entire volume in as close to 24 hrs as possible.
Tuesday -	No chemical to be pumped, but wash out tank and pump down the hole during morning.
Wednesday -	Mix 50 lbs (1 bag) of monosodium dihydrogen phosphate with 200 gals of water and pump in as close to 24 hrs as possible.
Thursday -	No chemical to be pumped, but wash out tank and pump down the hole during morning.
Friday -	Mix 50 lbs (1 bag) of monosodium dihydrogen phosphate with 200 gals of water and pump in as close to 24 hrs as possible.
Saturday -	No chemical to be pumped, but wash out tank and pump down the hole during morning.
Sunday -	No chemical to be pumped.

Above schedule is repeated each week for test patterns 1 and 3. The same concentrations are being employed in Test Patterns 2 and 4 except that 0.1% molasses (v/v) is being added on Wednesdays instead or monosdium dihydrogen phosphate.

(3). Core flood experiments

Core flood experiments were conducted during Phase I and the data derived therefrom used to formulate the feeding regime for the field demonstration as given in the preceding section. Representative results using potassium nitrate and sodium orthophosphate were reported in last years annual report and will not be repeated here. During Phase II, additional core flooding experiments were conducted using molasses as a microbial nutrient in addition to potassium nitrate and sodium orthophosphate. In a representative experiment, two core plugs were flooded with simulated injection water consisting of the following salts per liter of water.

218.0 $CaCl_2$
54.1 $MgCl_2$
94.4 $BaCl_2$
36.7 Na_2SO_4
697.2 $NaHCO_3$
2,958.0 NaCl

The control core received simulated injection water every day while the test core received simulated injection water plus nutrient supplements on the following schedule. Molasses in a concentration of 1% (v/v) on day 1, potassium nitrate in a concentration of 0.06% (w/v) on day 3, and disodium orthophosphate in a concentration of 0.04% (w/v) on days 5,7, and 9. This schedule was repeated every ten days for the duration of the experiment. As may be observed in Figure 1, the core plug was subjected to increased pressure (flushed) on days 33 and 43. As shown, the flow rate constantly increased in the control core plug.

Contrariwise, the flow rate of injection water through the test core decreased with time (Figure 2). After 61 days, the flow rate was increased by increasing the pressure on the influent (flushed) thereby increasing the flow of injection water through the core plug. Once again, flow rate decreased with time and the core plug was flushed a second time. This cycle was repeated two more times during the 187-day duration of the experiment.

The above experiment was repeated using injection water from the North Blowhorn Creek Oil Field instead of simulated injection water and two test core plugs were used, not just one. The flow of injection water through the control core plug was very limited, usually only one ml per day (see Figure 3). As may be observed in Figure 4, the flow rate through the first test core plug decreased with increasing time and was flushed twice to temporarily increase flow rate. Similar results were obtained with test core plug 2 (see Figure 5).

These experiments in which molasses was added to the feeding regime appeared to exhibit a more rapid decrease in flow rate than did previous experiments conducted using potassium nitrate and sodium orthophosphate alone. This result was expected since the molasses supplied the in situ microorganisms with a substrate more easily utilized than the crude oil.

(4). Tracer studies

Early in the planning stages for the project the first test well pattern was chosen because it had been observed in the field that the NBCU 2-14 No.1 injection well seemed to be very well connected to the 2-13 No.1 hydraulically. The 2-14 No.1 allowed injection at relatively high rates, and the 2-13 No.1 produced high fluid rates and was over pressured. It was theorized that the movement of water from the injector to producer would be quicker than in any other injection pattern. However, the need to have a quantitative time for fluid travel from injector to the producers in the first pattern led to the decision to conduct a radioactive

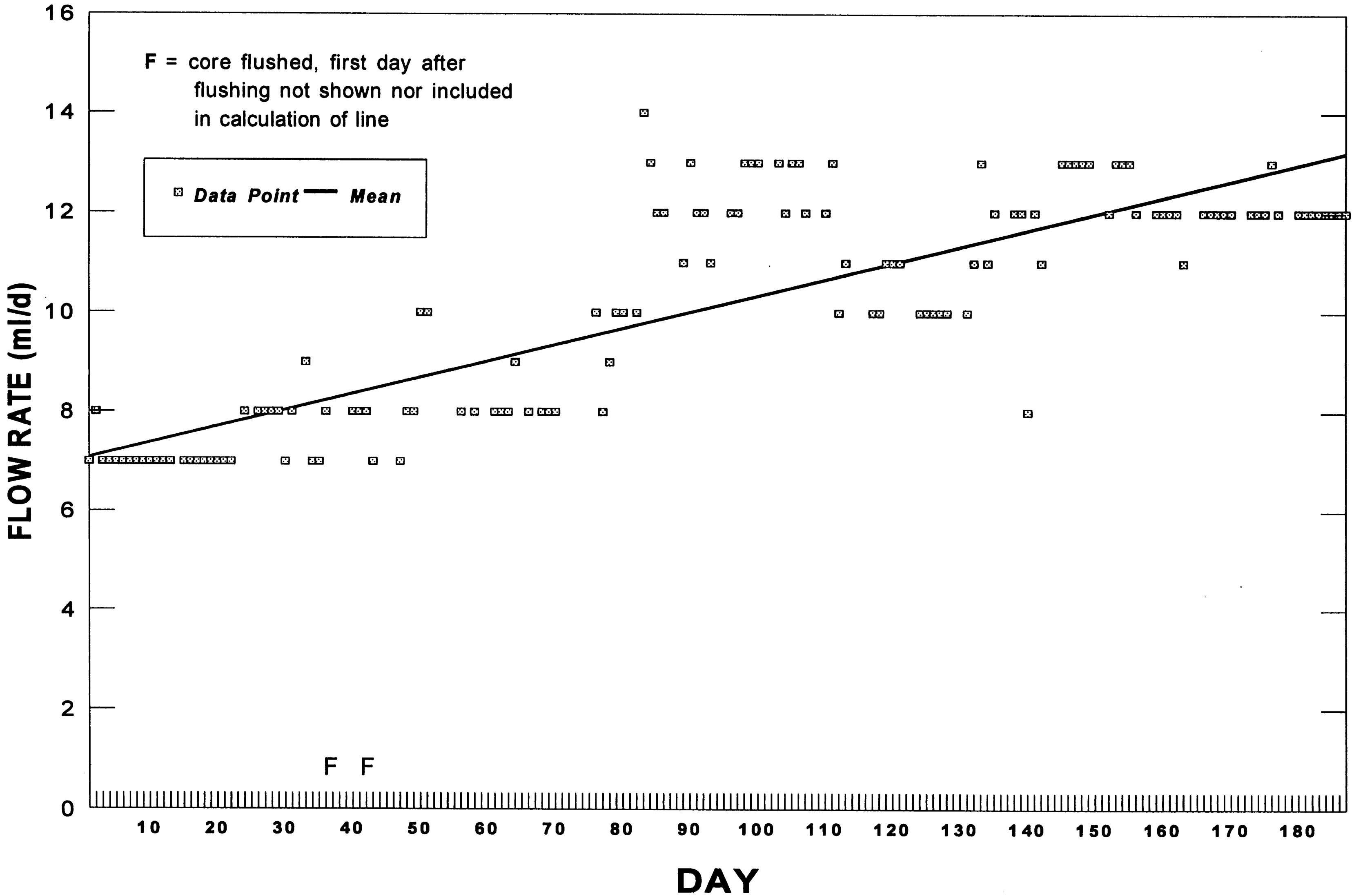


Figure 1. Flow rate of simulated injection water through control core plug.

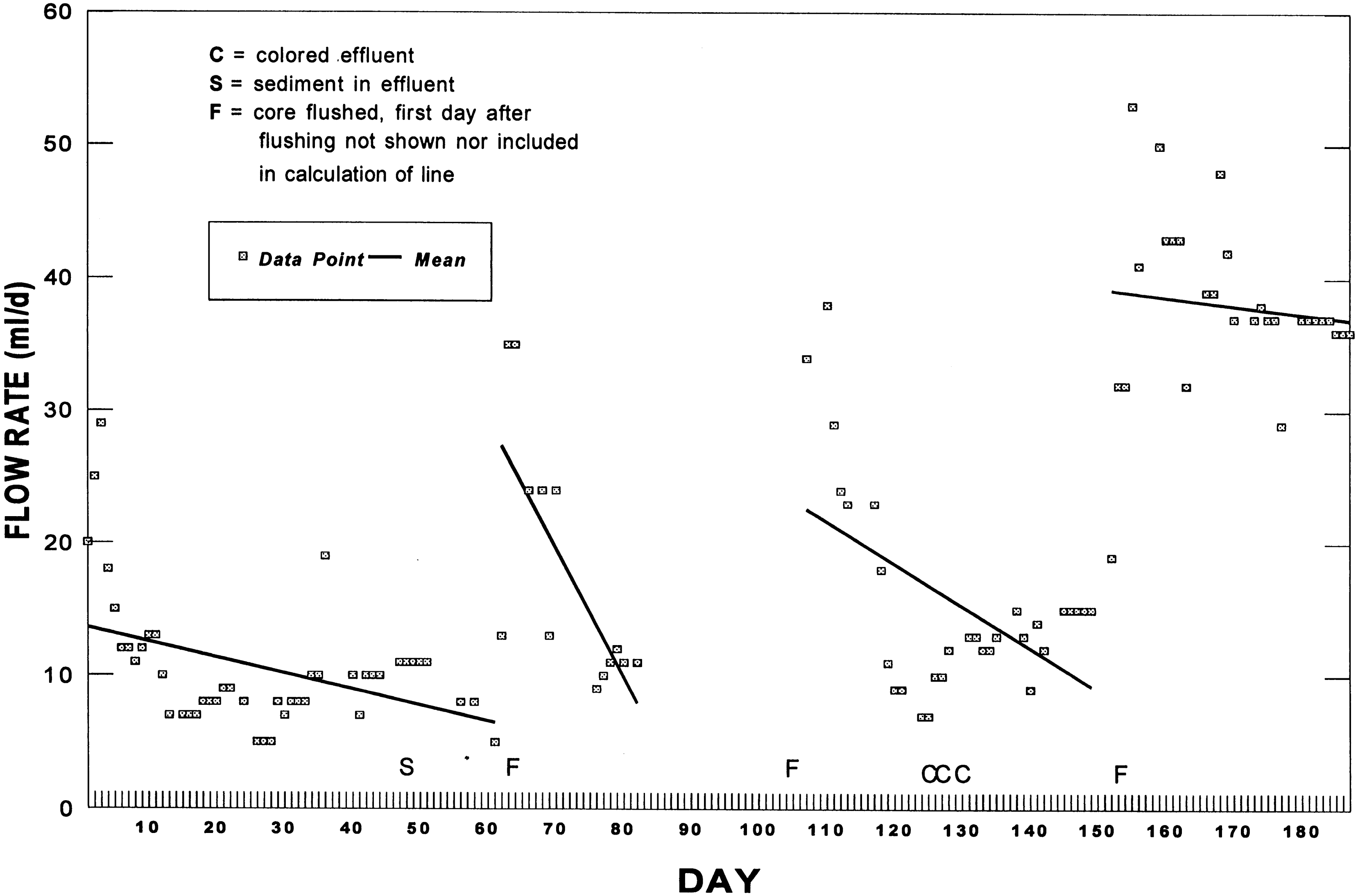


Figure 2. Flow rate of simulated injection water through test core plug.

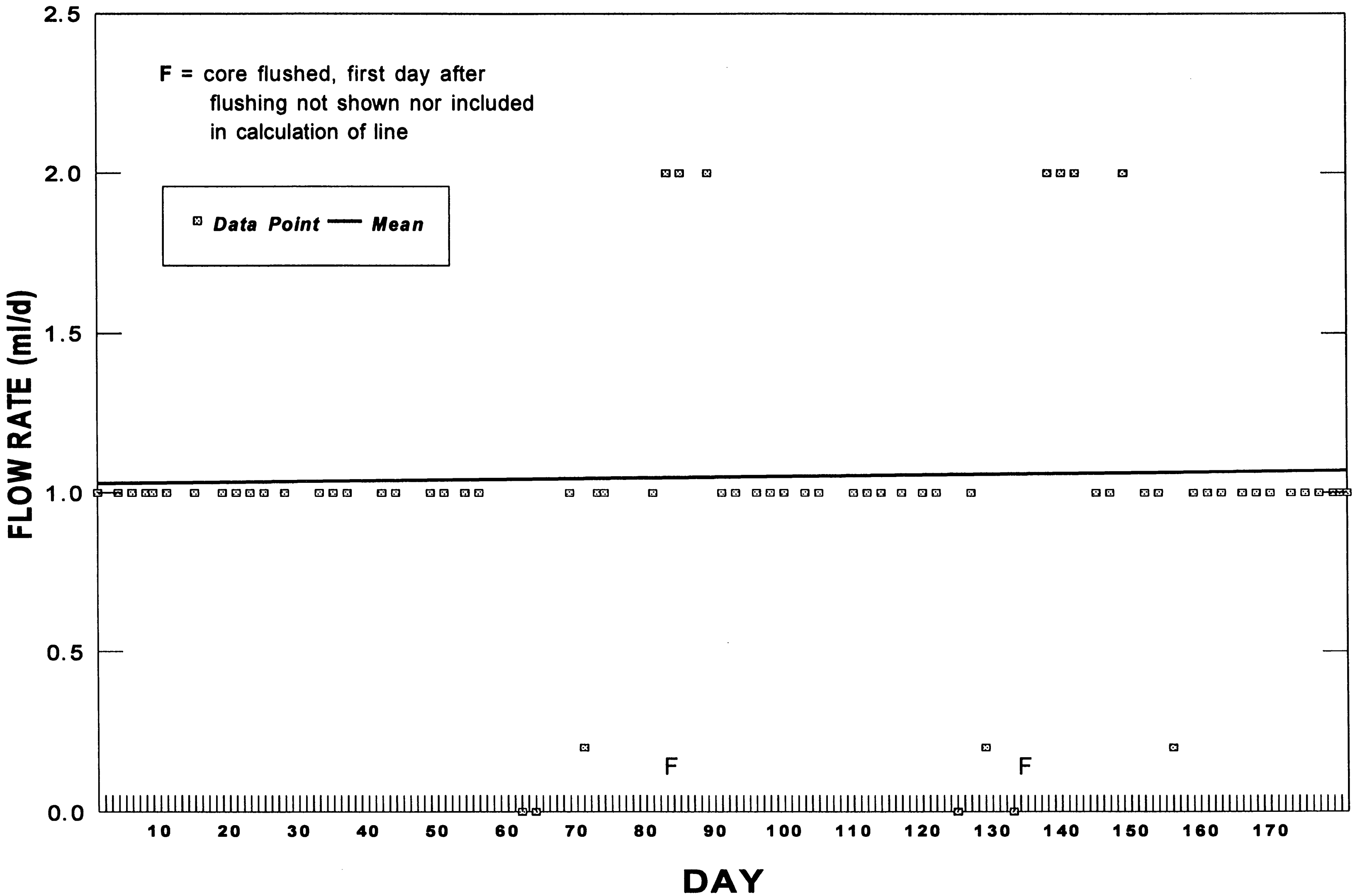


Figure 3. Flow rate of injection water from North Blowhorn Creek Oil Field through control core.

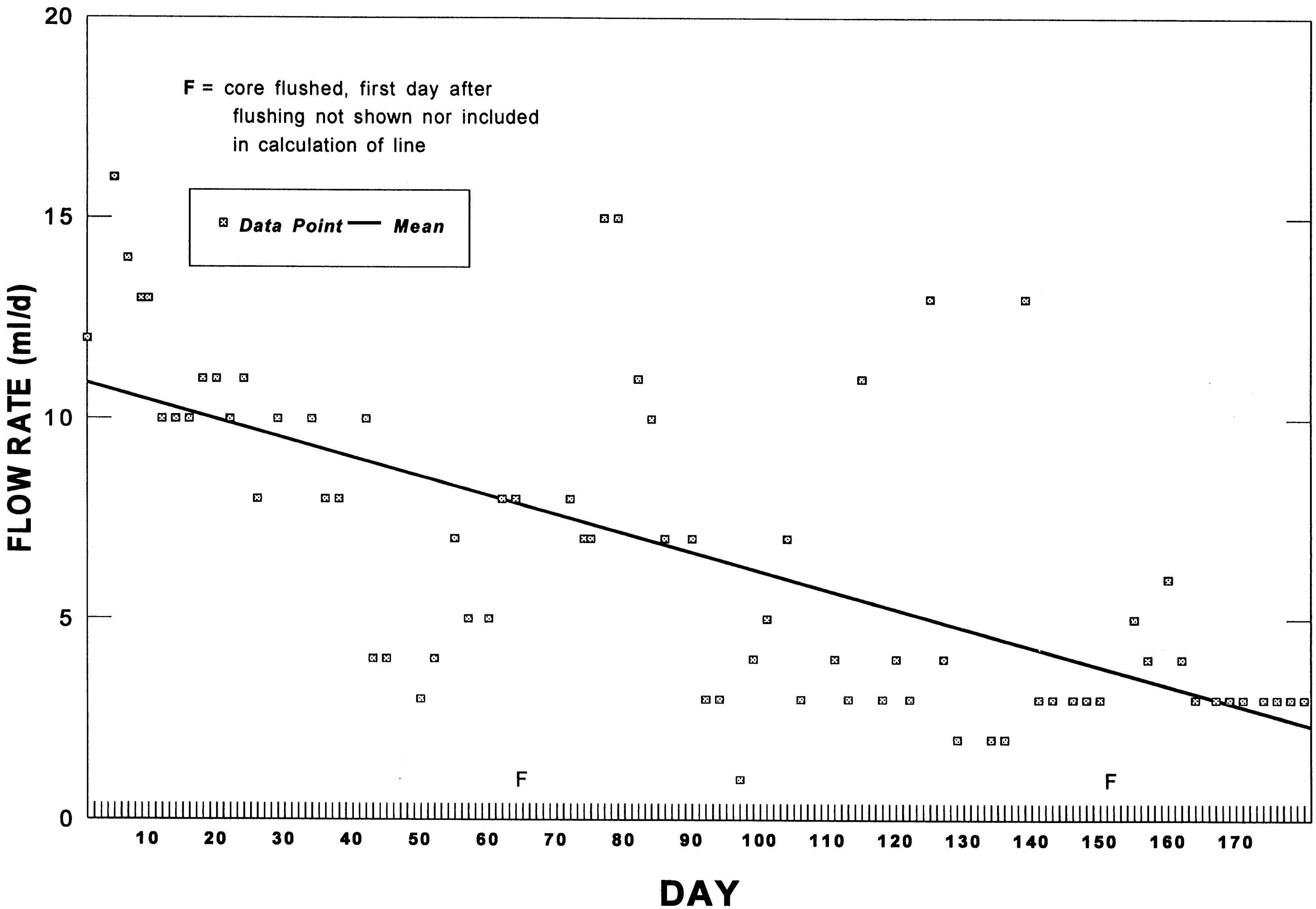


Figure 4. Flow rate of North Blowhorn Creek Oil Field injection water containing nutrients through test core plug 1.

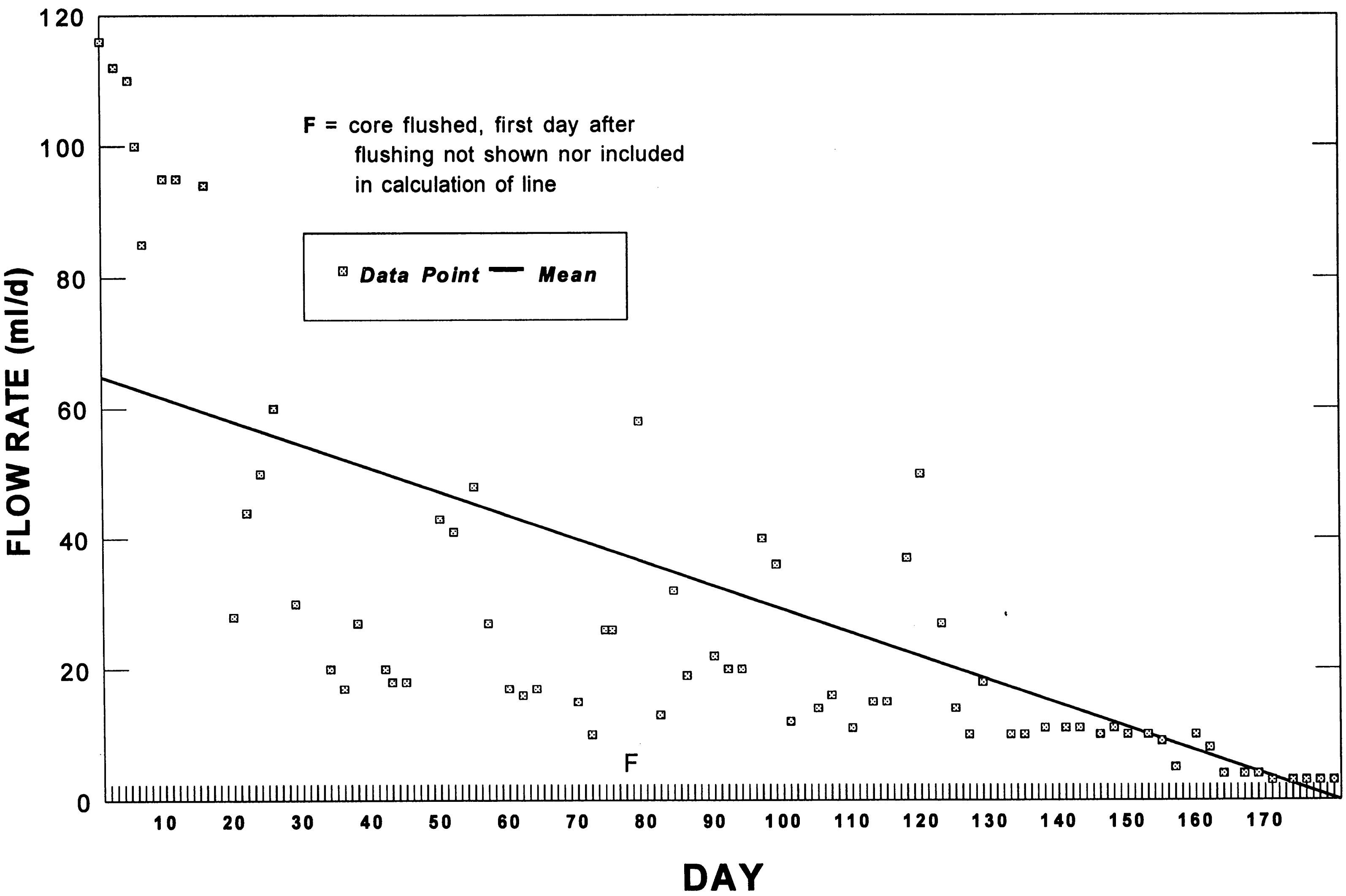


Figure 5. Flow rate of North Blowhorn Creek Oil Field injection water containing nutrients through test core plug 2.

tracer survey. If the travel time could be established, then some time frame for the effects of microbial activity to become detectable could be established.

On April 27, 1994, 2 Ci of tritiated water was injected into the 2-14 No.1 well. Weekly and then monthly sampling of water from the four test pattern producing wells was carried out. No trace of the material was detected by the laboratory analysis of the water samples until October 12 when 14 pCi/ml was detected in the 2-13 No.1 well. On November 9, the same well sample tested 41 pCi/ml and 1.9 pCi/ml also was found in the 2-15 No.1 well. Sampling of the water is continuing, but preliminary results indicate that six to seven months are required for injection water to travel to the producers. Consistent traces of Tritium began to be detected in the 11-3 No.1 well on October 18, 1995. Thus, evidence of microbial activity could not be expected to be detectable in less than seven months and probably closer to a year after initiation of nutrient injection.

b. Geological Characterization of Core Samples

The geological information gathered from the recovered core samples, and from the future wells to be drilled and cored in Phase 2 of the project, are required for the proper evaluation of the MEOR process being employed in this project. Recovered core samples have been characterized petrographically and also by thin section, Secondary Electron Imagery (S.E.I.) and x-ray diffraction analyzing methods.

c. Petrophysical Study of Core Samples

Study of petrophysical properties of collected core samples from newly drilled well 34-3 No. 2 continued. Based on data from over 20 samples, the core plugs show strong heterogeneity since porosity and permeability vary significantly from sample to sample and even within the same core plug (see Table 1). The formation connate water saturation varied from 14 to 17 percent which is an indication of unswept oil zones in the reservoir.

d. Analysis of Injection and Production Fluids

Fluids from both injector wells and producer wells of 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 oil field lease operator.

(1). Petrophysical analyses

The following experiments have been performed on produced fluids:

- Gas chromatography (GC) to determine the aliphatic profile of oil from producer wells in all patterns
- Gravity (API) of oil (at room temperature) produced from selected wells in test and control patterns

Table 1. NBCU 34-3 No. 2 Porosity and Permeability of Collected Core Samples

No.	Depth.	Porosity	Permeability, md		Grain Density
	feet	pc	gas	liquid	gr/cc
1	2333	18.9	24.8	11	2.35
2	2332	18.5	25.9	8.88	NA
3	2332	16.25	88	36	NA
4	2332	15.16	108	36	2.54
5	2331	15.16	4.7	9.6	NA
6	2330	NA	30.2	9.22	NA
7	2330	NA	21.38	8.82	2.25
8	2330	15.89	15.89	3.79	NA
9	2330	NA	24.77	3.51	2.41
10	2330	NA	14.79	10.96	NA
11	2329	15.16	30.2	9	2.73
12	2329	15.16	18.6	3.6	NA
13	2329	15.16	19.8	10.1	NA
14	2329	16.25	122	66	2.44
15	2329	15.6	108	36	NA
16	2329	16.25	88	36	NA
17	2323	19.79	26.8	41.78	NA
18	2323	14.98	42	41.77	2.81
19	2323	NA	39	41	2.27
20	2323	NA	26.8	8.1	2.3

- Viscosity of oil (at reservoir temperature) produced from selected wells in test and control patterns
- Interfacial tension (IFT) for produced and separated oil-water system from selected wells in test and control patterns
- Surface tension (ST) of air-water systems as in IFT
- pH of produced water

Additionally, fluid (oil-gas-water) production rates for producer wells in all patterns were routinely measured on site and stored in the main database for further studies.

(2). Microbial populations

Water samples were obtained from the wellhead of all injector wells and producing wells in all test and control patterns in this study. Samples were evaluated for total heterotrophs and oil-degrading microorganisms under both aerobic and anaerobic conditions. Numbers of microorganisms varied widely from month to month, even from the same well and consequently no definitive conclusions can be drawn in regard to the impact of nutrient additions to the injection water. There are, however, several generalizations that have been observed. Usually, the microbial content of the injection water exceeded that of the produced water and on a few occasions reached over one million cells per ml. Total heterotrophs outnumbered oil-degrading microorganisms in both injection water and production water. Also, anaerobes were in greater number than were aerobes in all systems. In most cases, there were greater numbers of oil-degrading microorganisms in the production water from wells in the test patterns than there were in the production water from the wells in the control patterns.

(3). Inorganic ions

Water samples were obtained from the wellhead of all injector wells and producing wells in all test and control patterns in this study. Samples were analyzed for hardness ($CaCO_3$) plus six inorganic ions. To date no changes in the inorganic content of the produced waters can be attributed to the nutrient additions to the injection water.

Three-fourths of the samples had hardness ($CaCO_3$) values in the range of 100-300 mg/l and two-thirds of the samples had chloride values in the range of 2,000-4,000 mg/l. Ninety-six percent of the samples had a potassium content of the 2-10 mg/l. The sulfate content of the water samples was less than 50 mg/l in 60% of the cases and less than 100 mg/l in 88% of the cases. Very few samples contained sulfide ions - less than 24% contained 1 mg/l or more.

Neither nitrate ions nor orthophosphate ions have been observed in production water from any of the wells and would not be expected to be present in light of the results of the tracer study.

e. <u>Criteria for Evaluating Success</u>

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 microorganism
- 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 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. Analysis of the other plots will result in proof/lack of proof of in situ microbial stimulation. Microorganisms, as by-product 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 will indicate changes in the historic aliphatic profile of the oil.

f. <u>Performance of MEOR Process in Pattern 1</u>

This project was initiated in January of 1994, and it is almost halfway through. Considering the starting injection date of each pattern (test Pattern 1, November 21, 1994; test Pattern 2, Feb 27, 1995; test Pattern 3, Jan 16, 1995, and test Pattern 4, Feb 27, 1995) and also considering the injection fluid in situ traveling time, only the performance of Pattern 1 is significant for interpretation and analysis at this time. Therefore, as a representative of the above mentioned operation, performance of Pattern 1 (test and control) wells are presented here (see Figures 6-19).

Analysis of data for well 2-13 No.1, as a representative of Pattern 1 test wells, indicates that the oil production rate is steadily increasing or holding while production of water and therefore WOR are falling, a very favorable indication (see Figures 6 and 12). Other petrophysical properties are given in Figures 20-24.

Analysis of data for well 2-3 No.1, as a representative of Pattern 1 control wells, indicates that the oil production rate is falling while the production of water and therefore WOR are rising, a very unfavorable condition (see Figure 17).

Analysis of IFT for well 2-13 No.1 as a representative of Pattern 1 test wells clearly shows a steady decrease in interfacial tension between oil and water (see Figure 22). This is a clear sign of microbial activities in the reservoir and a very favorable indication for oil production and oil-water separation.

HUGHES EASTERN CORPORATION
NBCU 2-13 NO. 1

PRODUCTION V. TIME

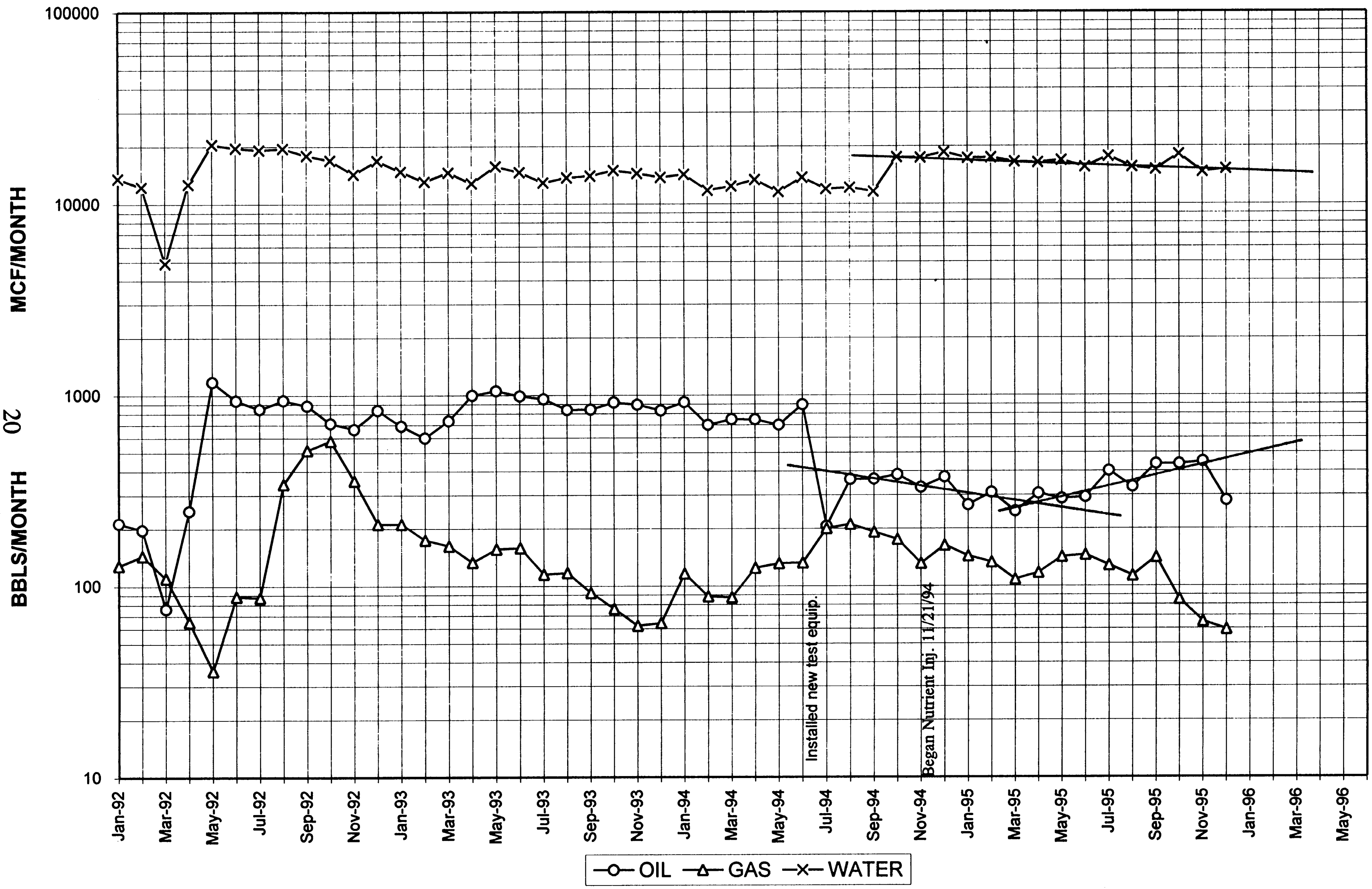


Figure 6: Reversal in oil production decline occurred within five months of start of nutrient injection. Note decline in water rate. This is the well in which tracer was detected about six months after injection into NBCU 2-14 No. 1.

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NBCU 11-3 NO. 1

PRODUCTION V. TIME

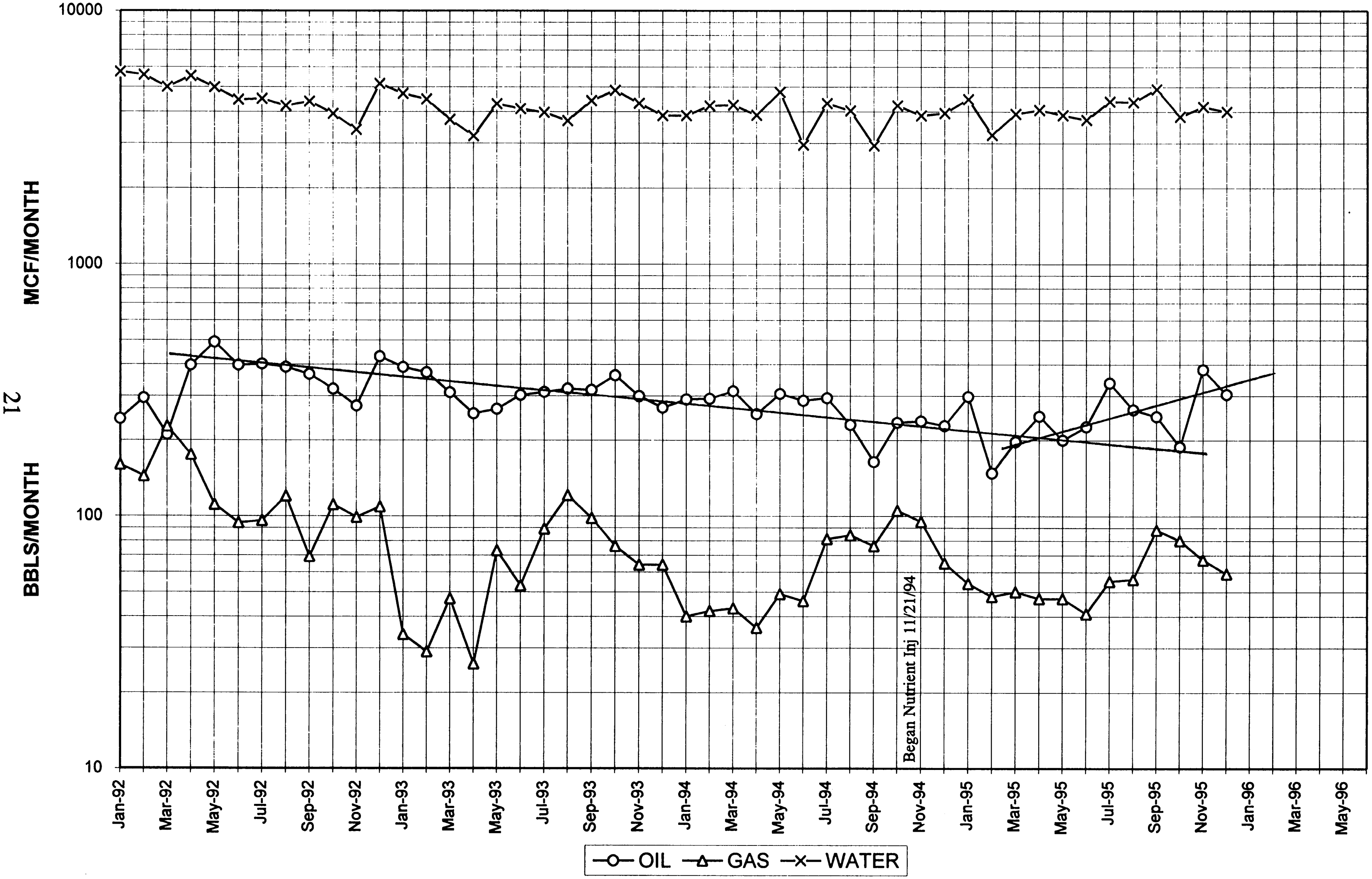

Figure 7: An increasing production trend appears to have begun about six months after start of nutrient injection.

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NBCU 2-11 NO. 1

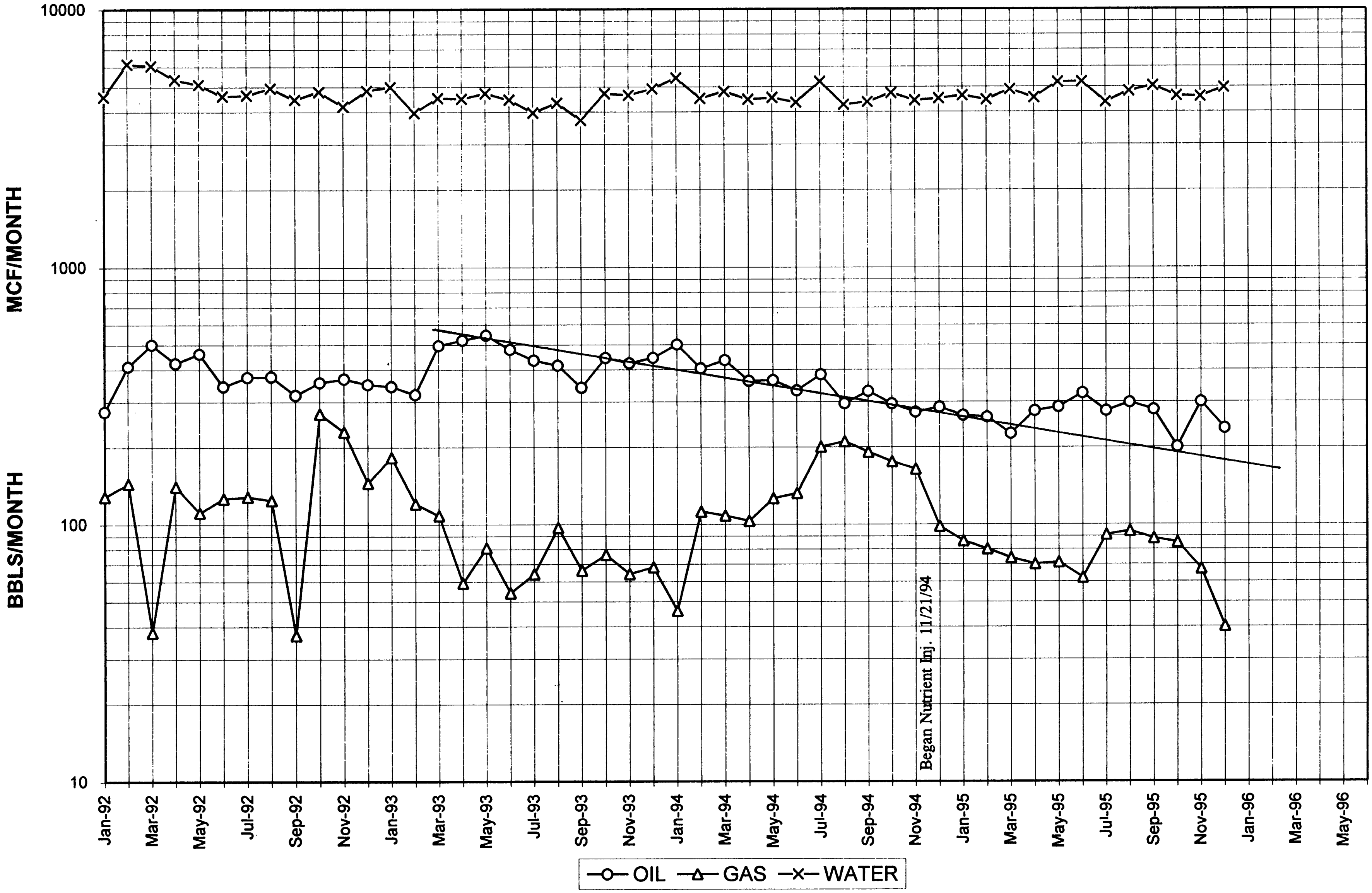
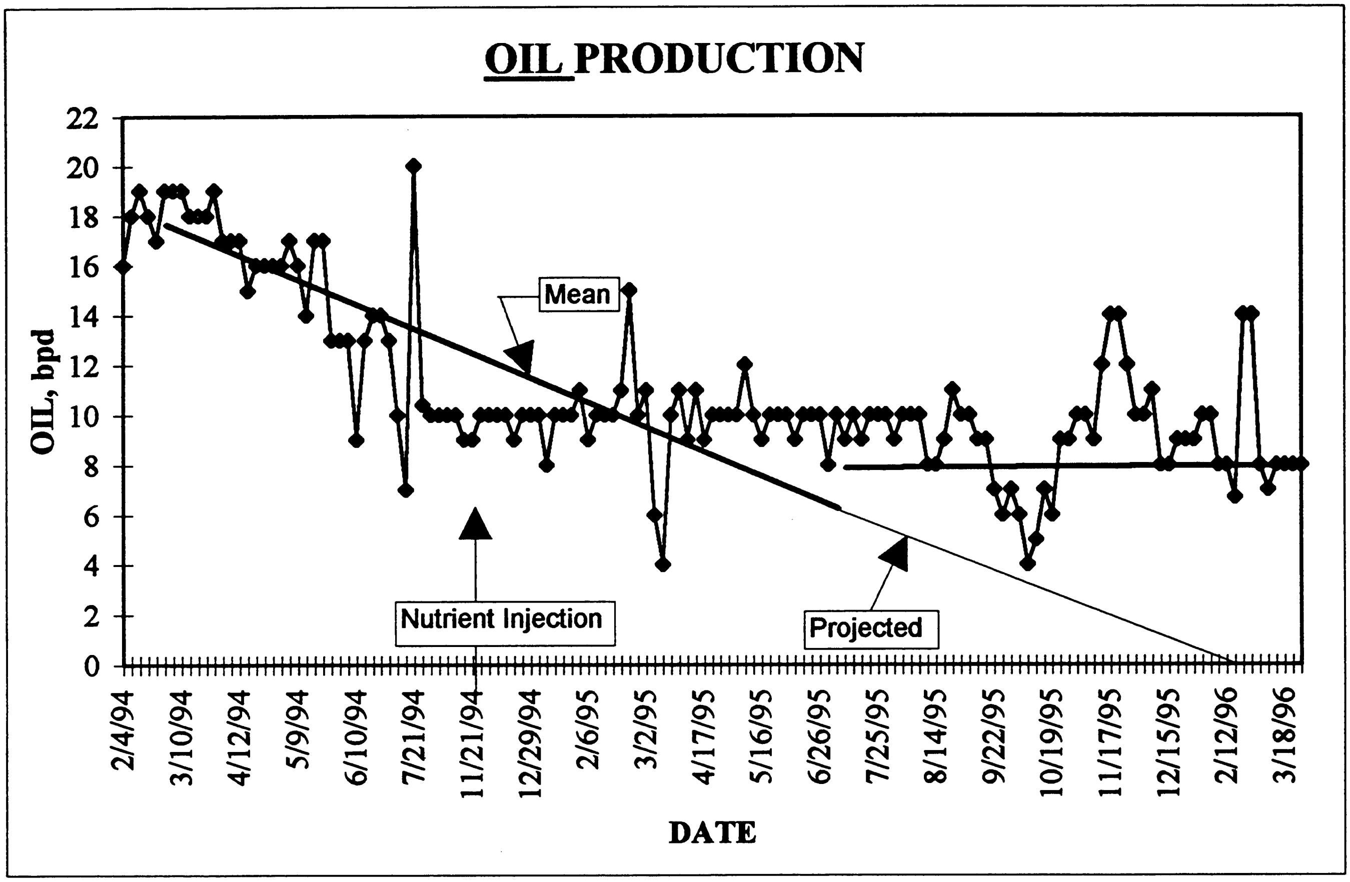


Figure 6: Reversal in oil production decline occurred within five months of start of nutrient injection. Note decline in water rate. This is the well in which tracer was detected about six months after injection into NBCU 2-14 No. 1.

Fig. 9-PERFORMANCE OF PATTERN 1 TEST WELL 2-11 No.1



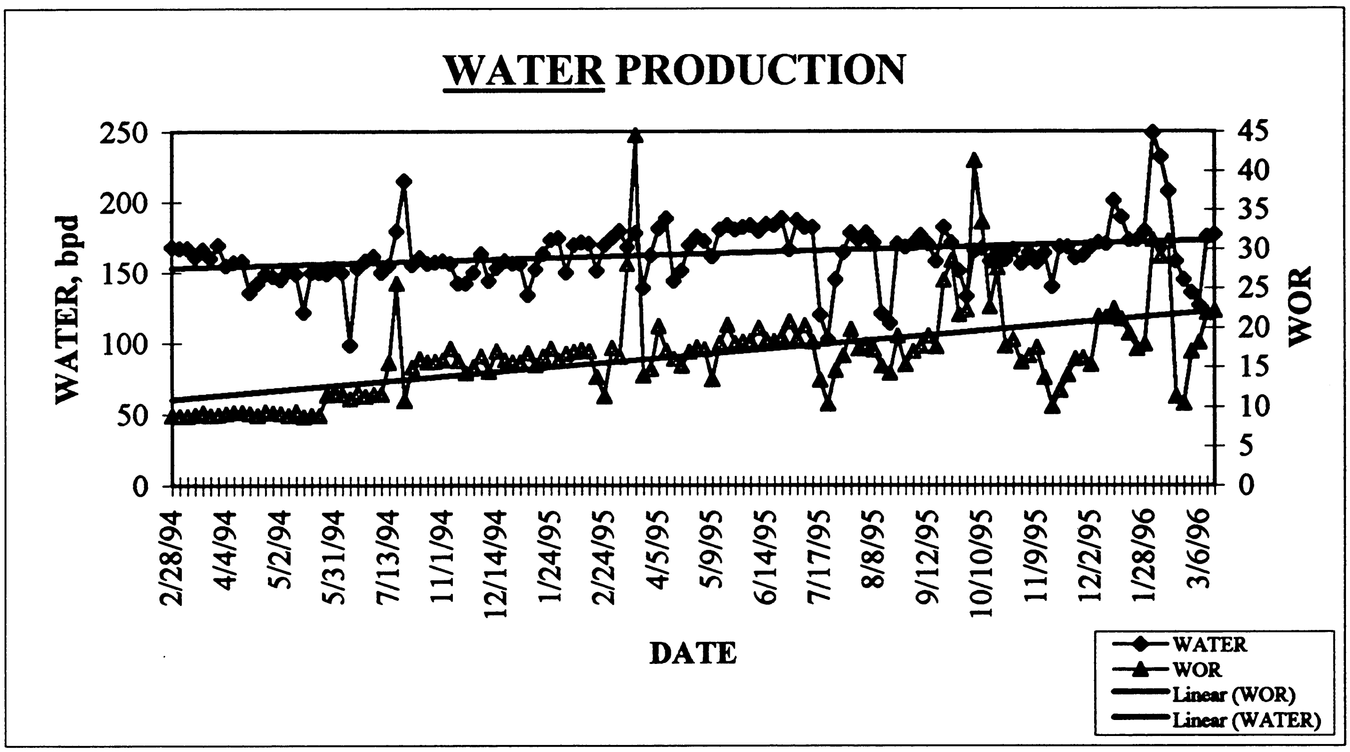
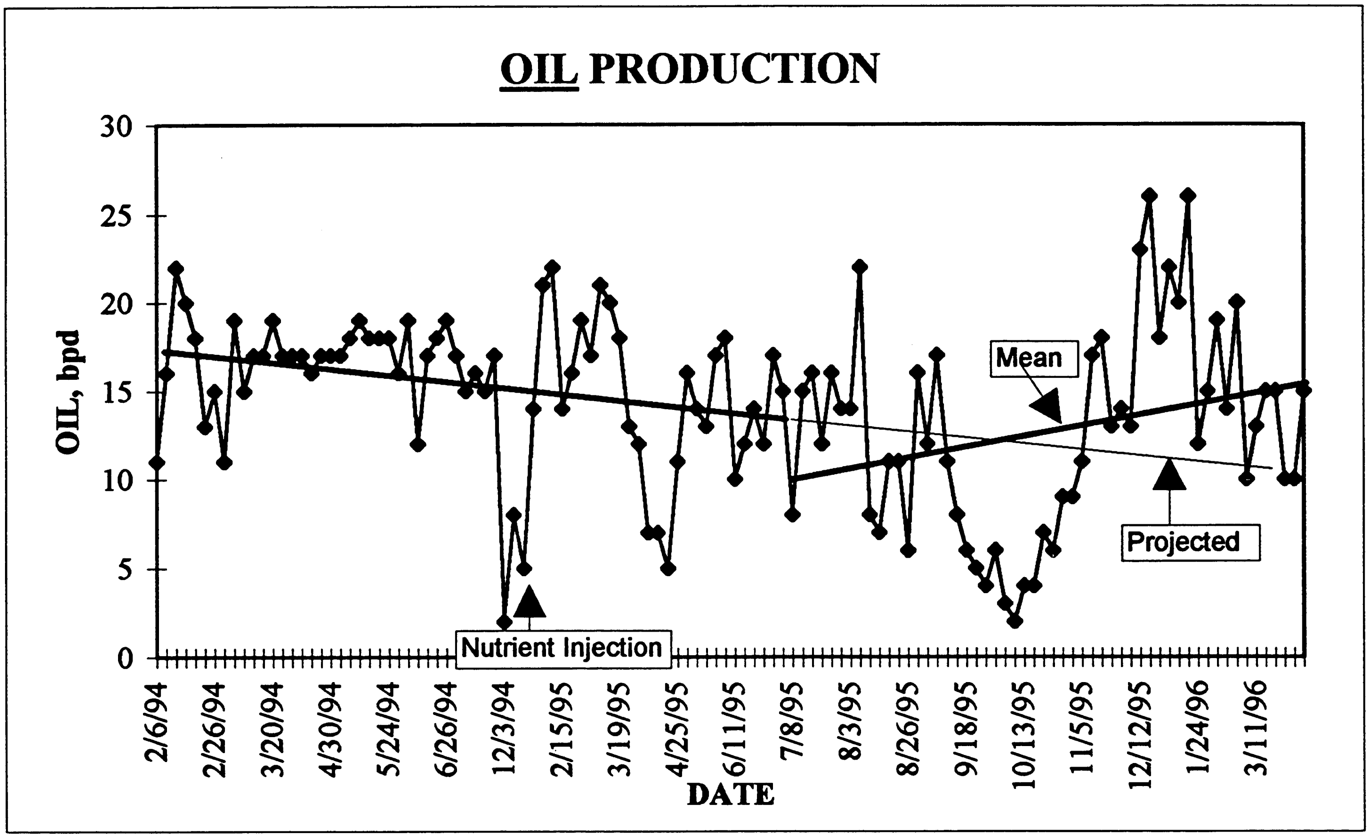


Fig. 10- PERFORMANCE OF PATTERN 1 TEST WELL 2-15 NO.1



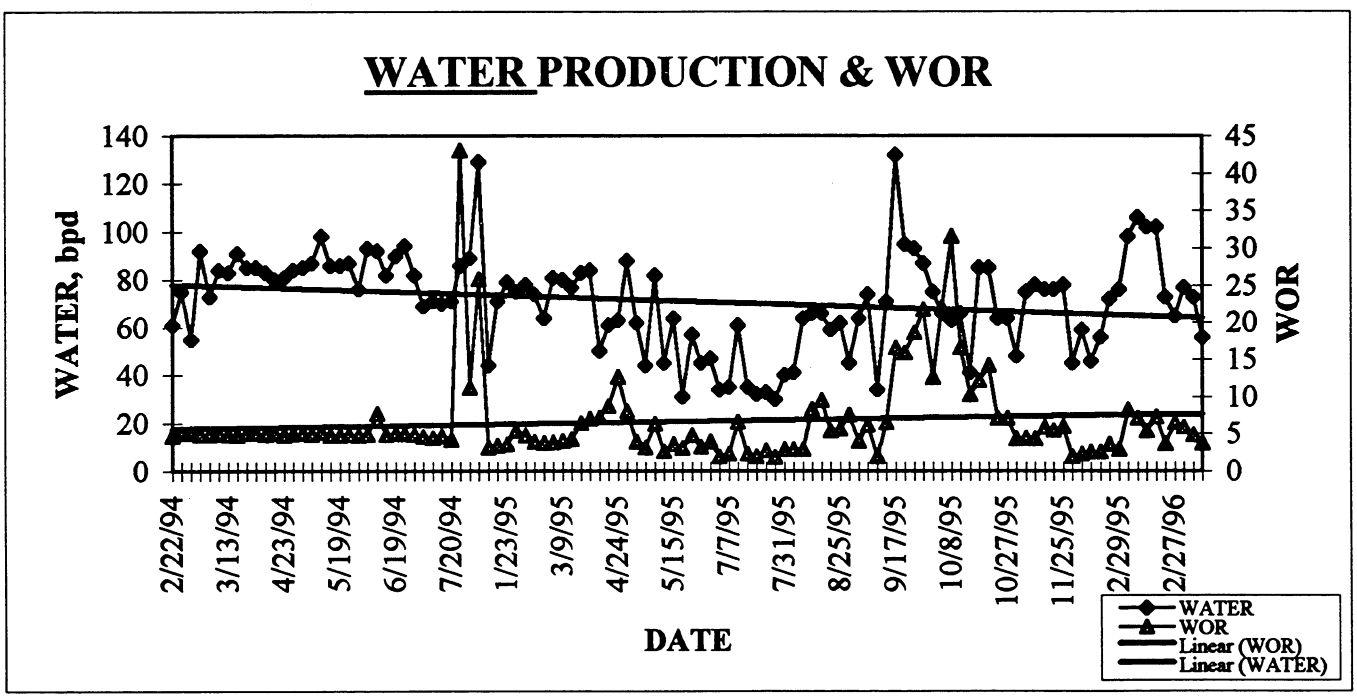
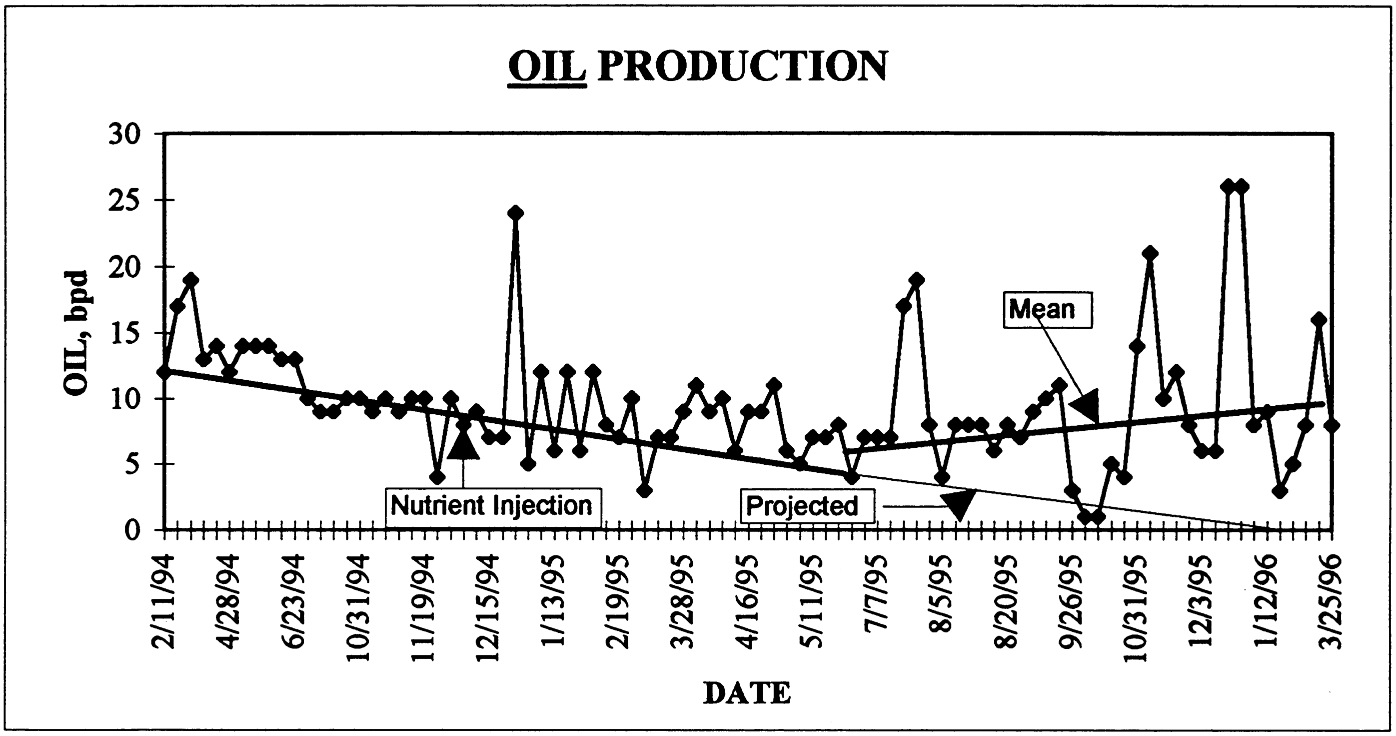


Fig. 11- PERFORMANCE OF PATTERN 1 TEST WELL 11-3 No.1



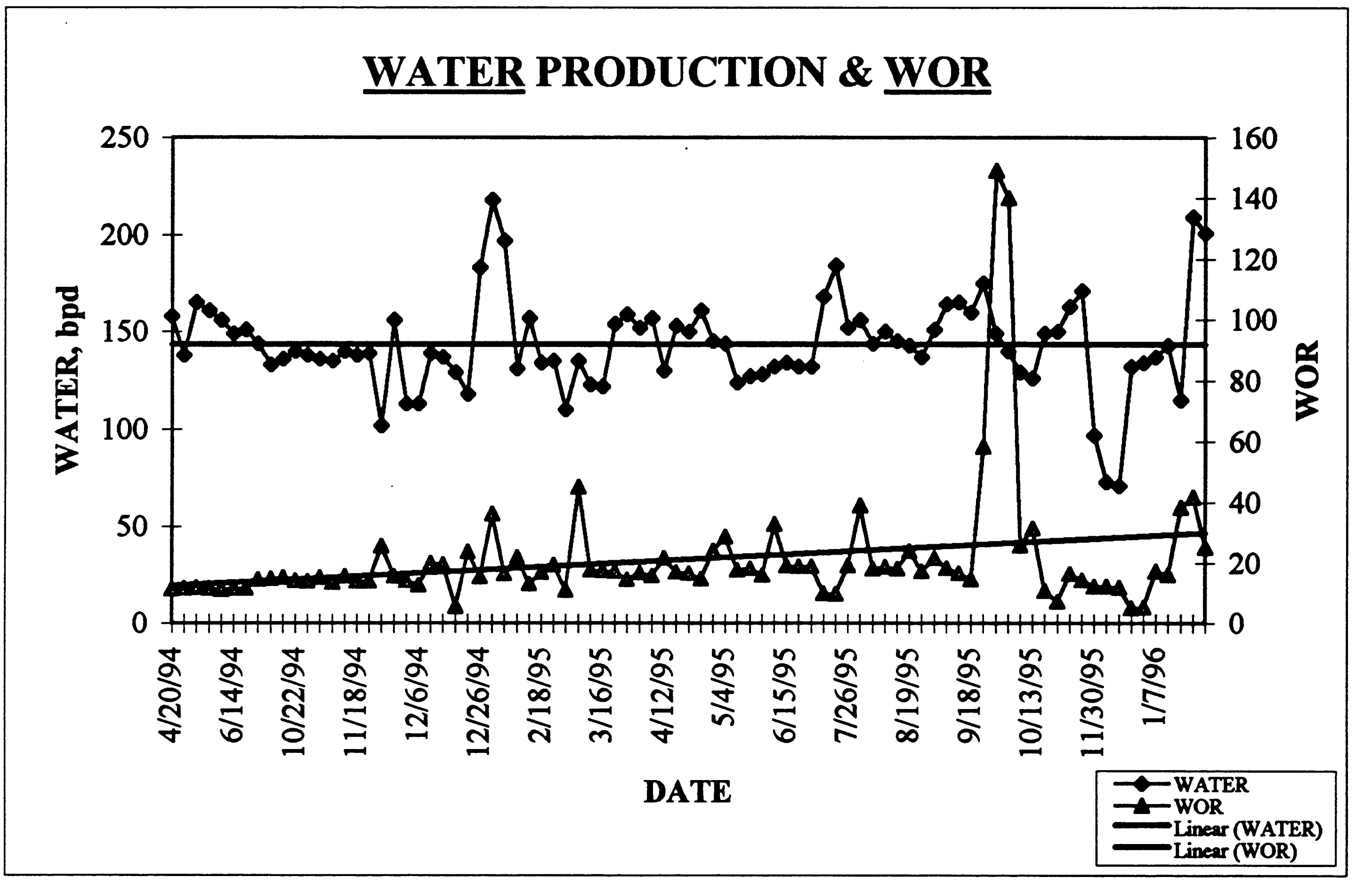
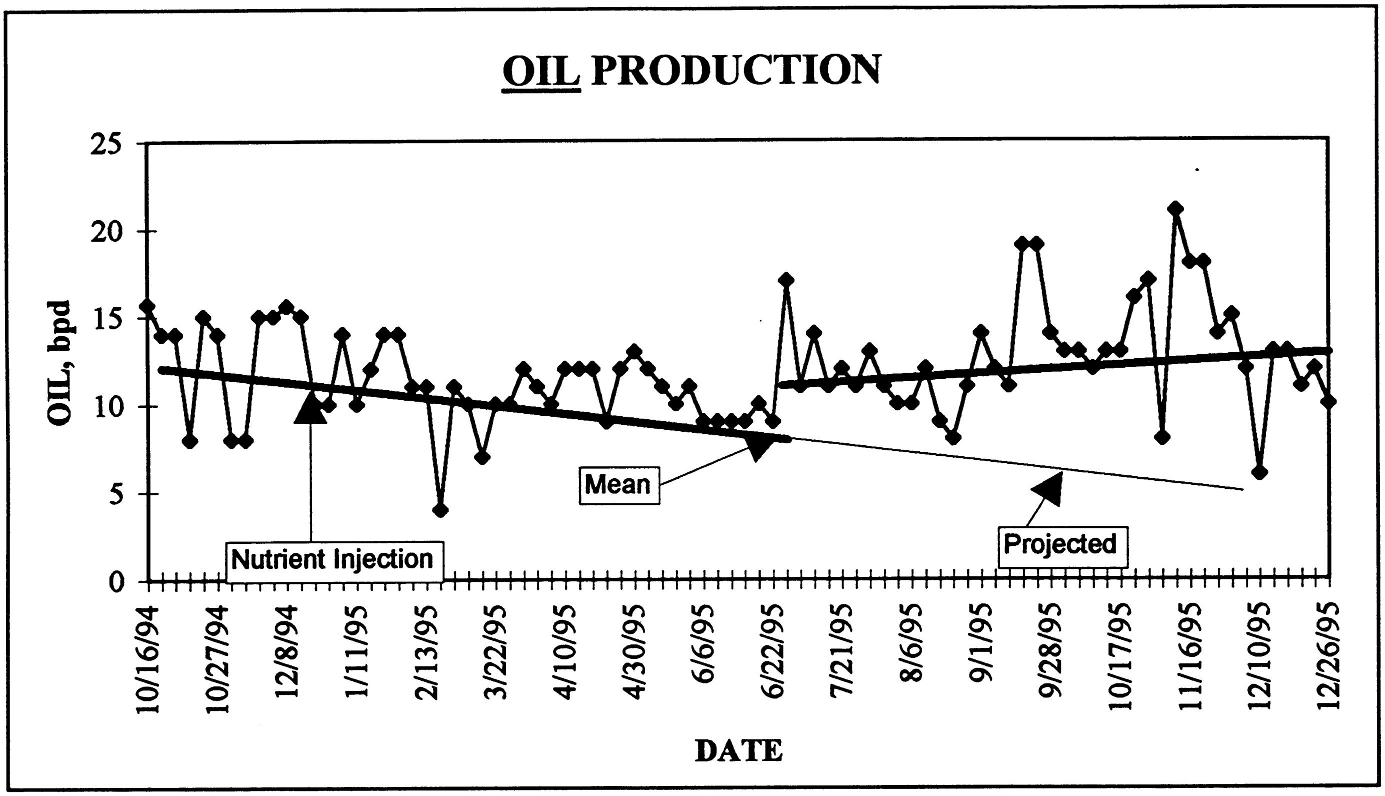


Fig. 12- PERFORMANCE OF PATTERN 1 TEST WELL 2-13 No.1



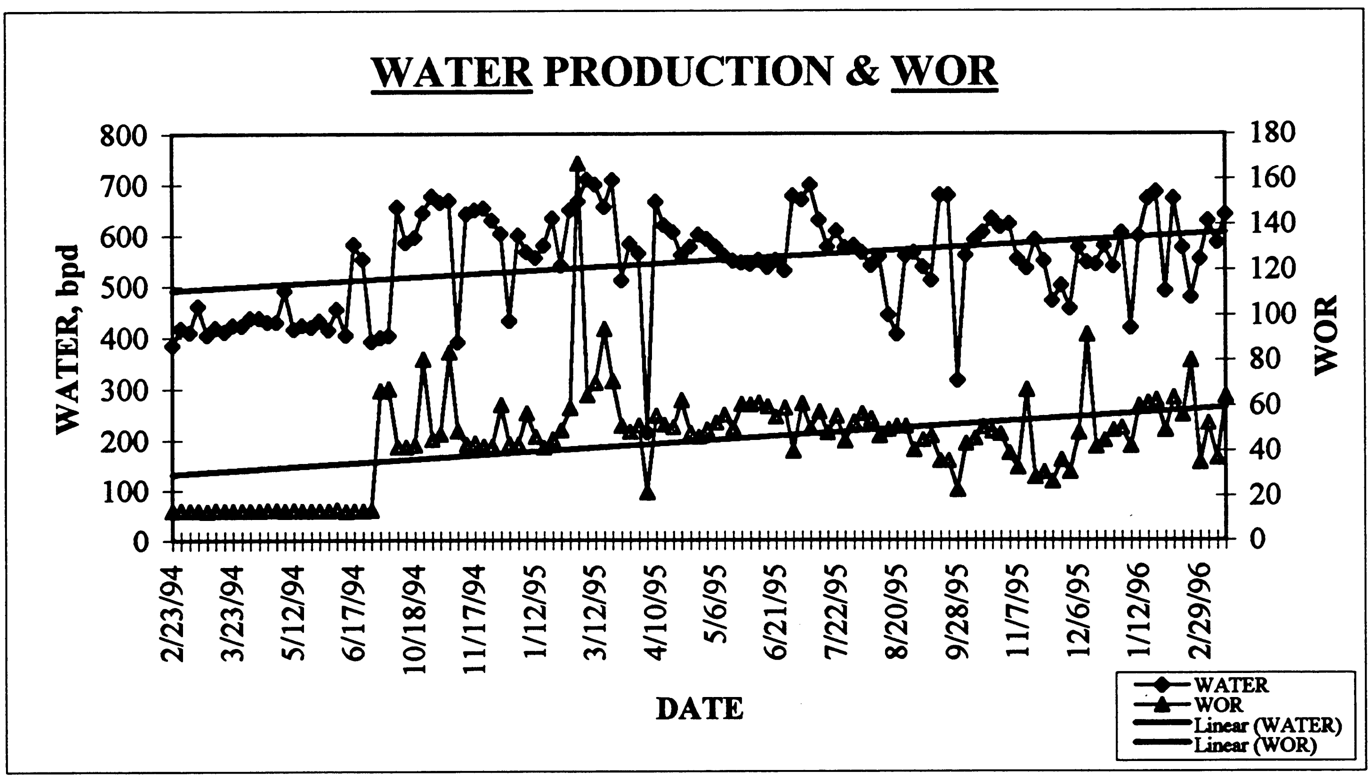


Fig. 13- HISTORY OF WATER INJECTION FOR TEST PATTERN 1 WELL 2-14-1

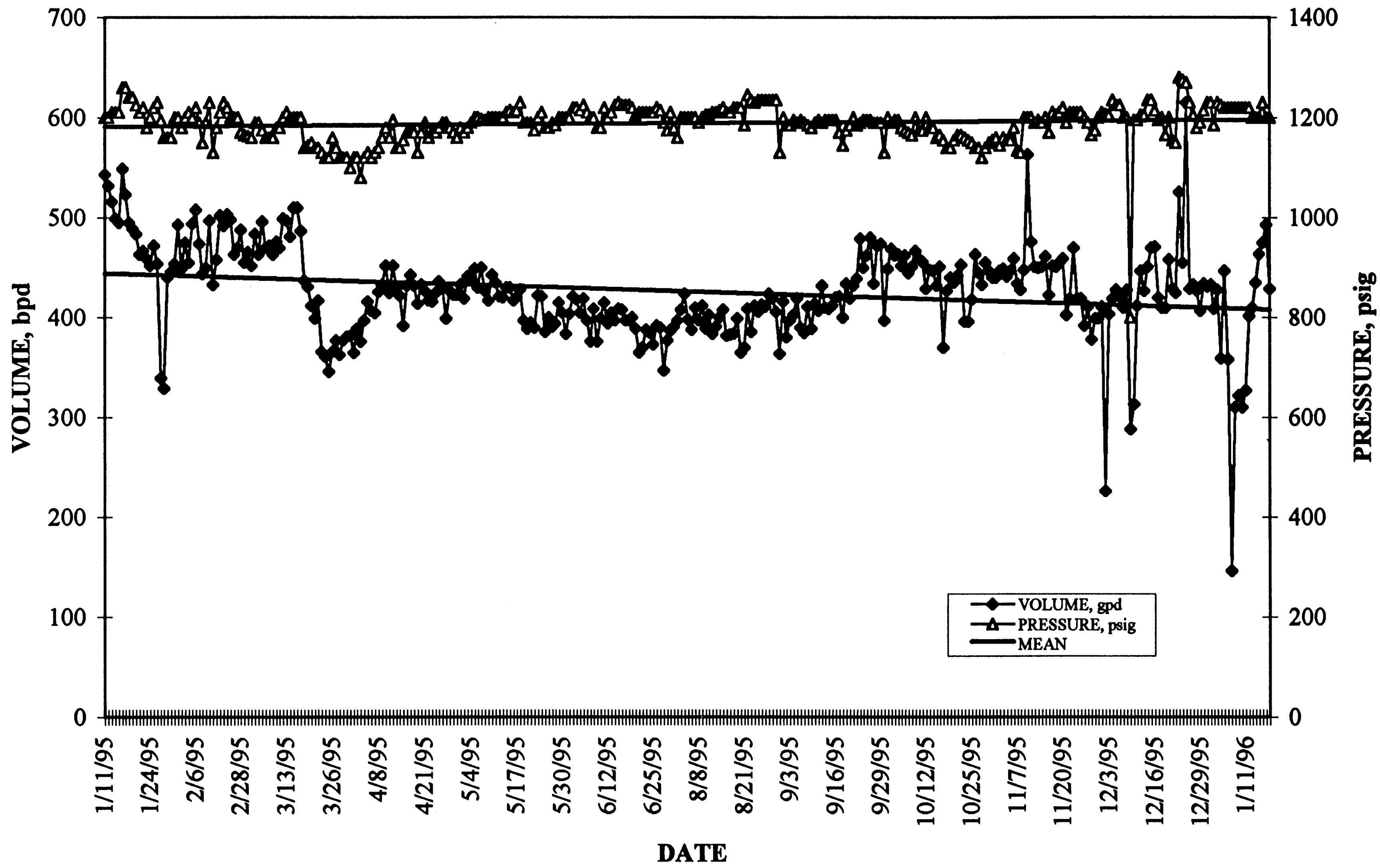
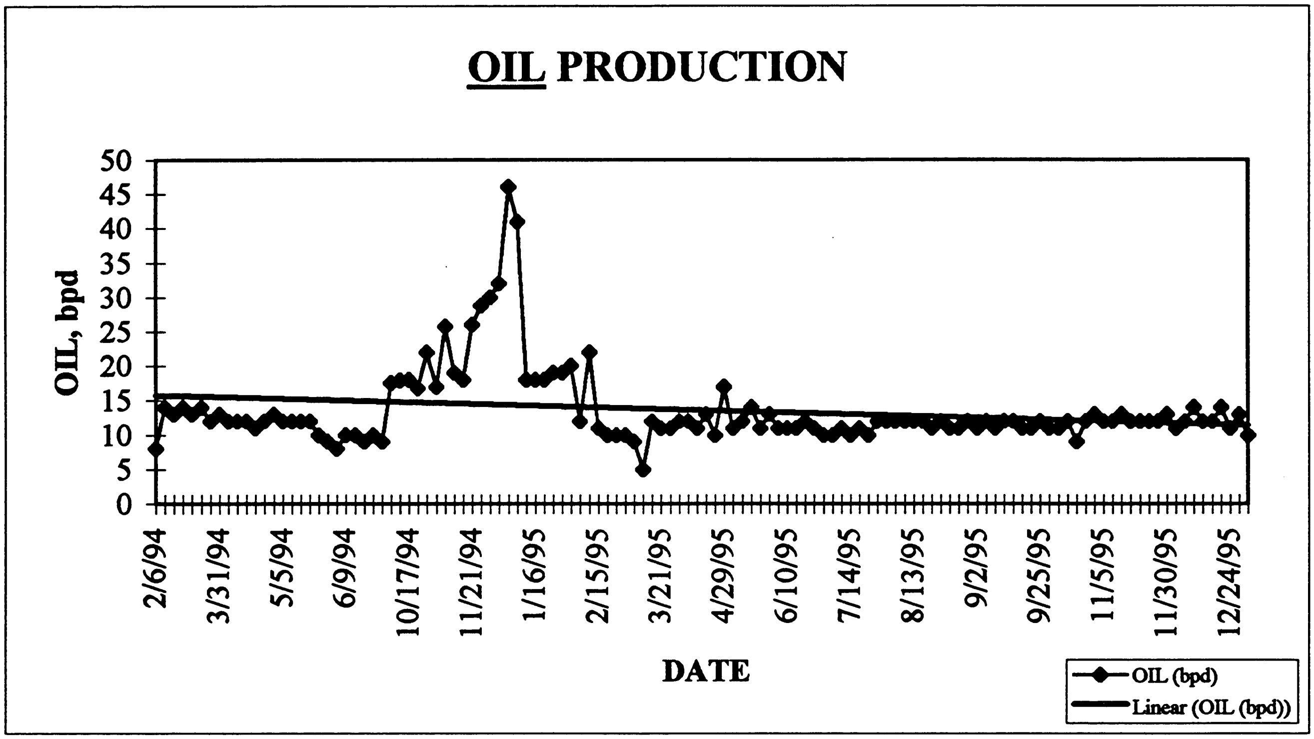


Fig.14- PERFORMANCE OF PATTERN 1 CONTROL WELL 35-13 No.1



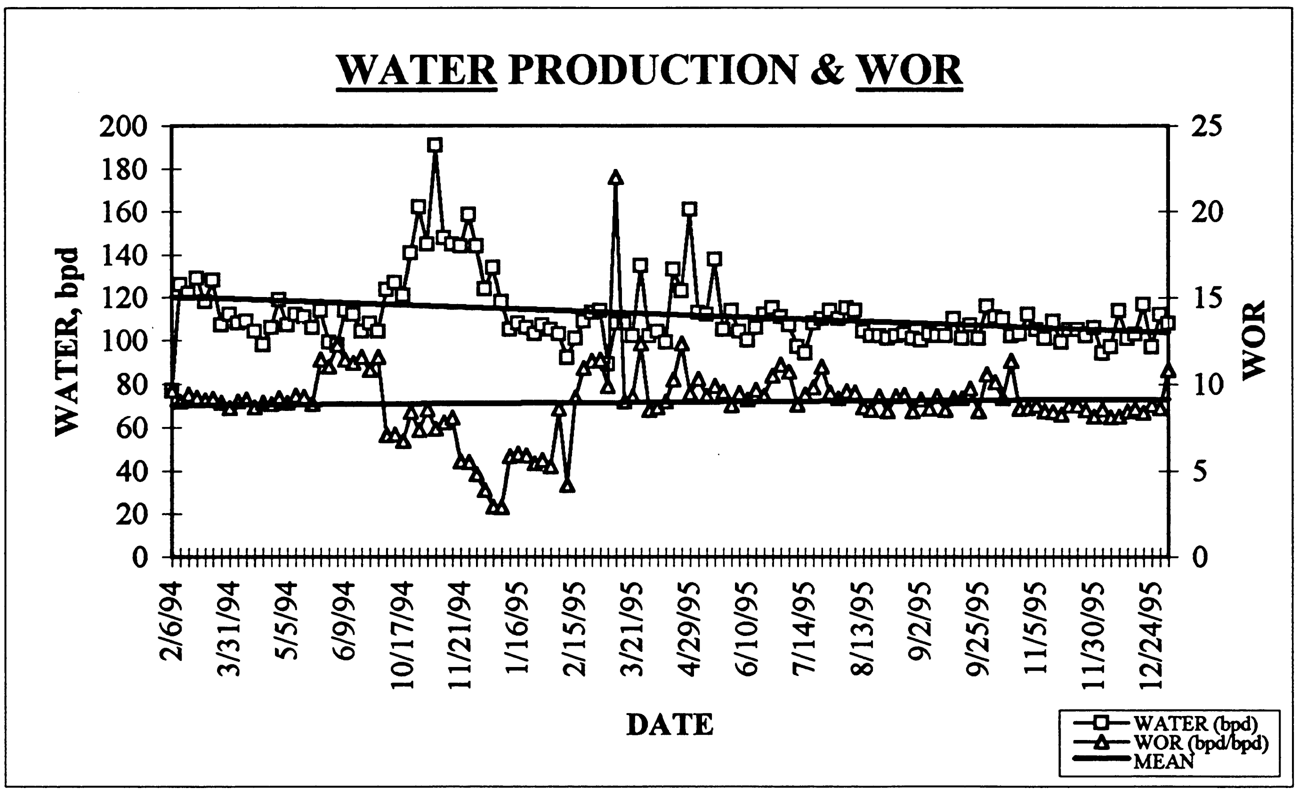
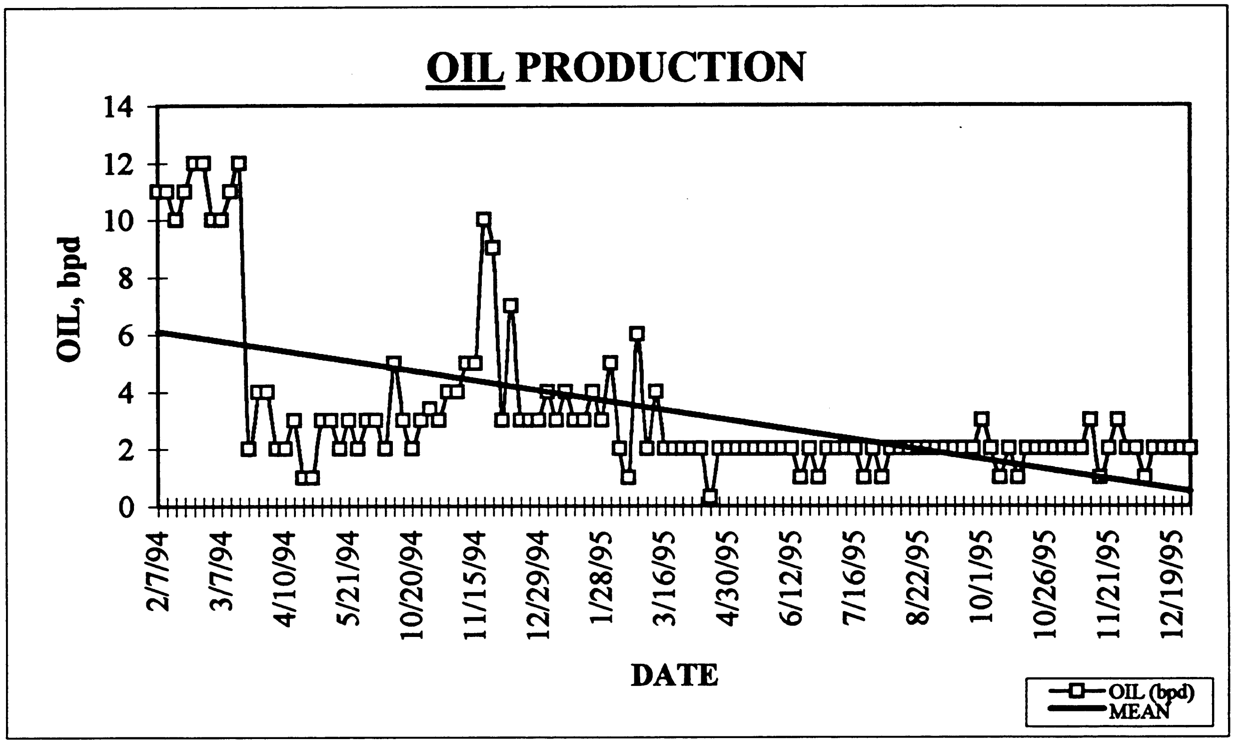


Fig. 15- PERFORMANCE OF PATTERN 1 CONTROL WELL 35-14 No.1



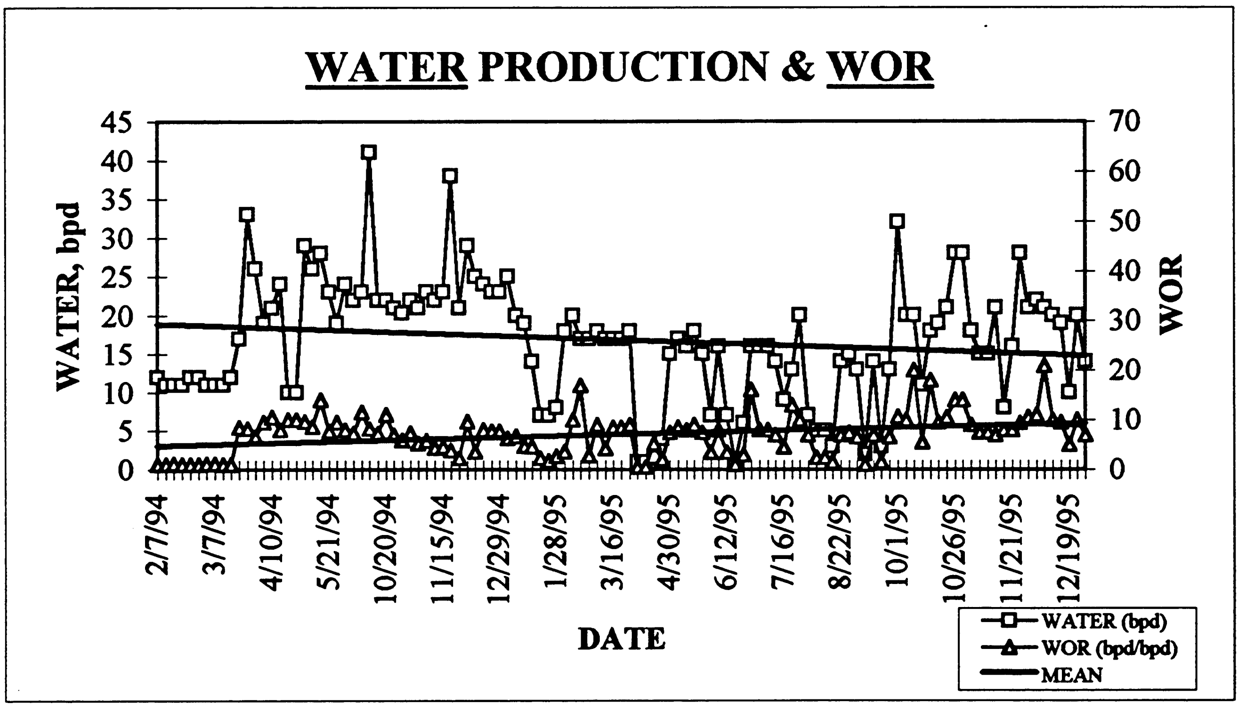
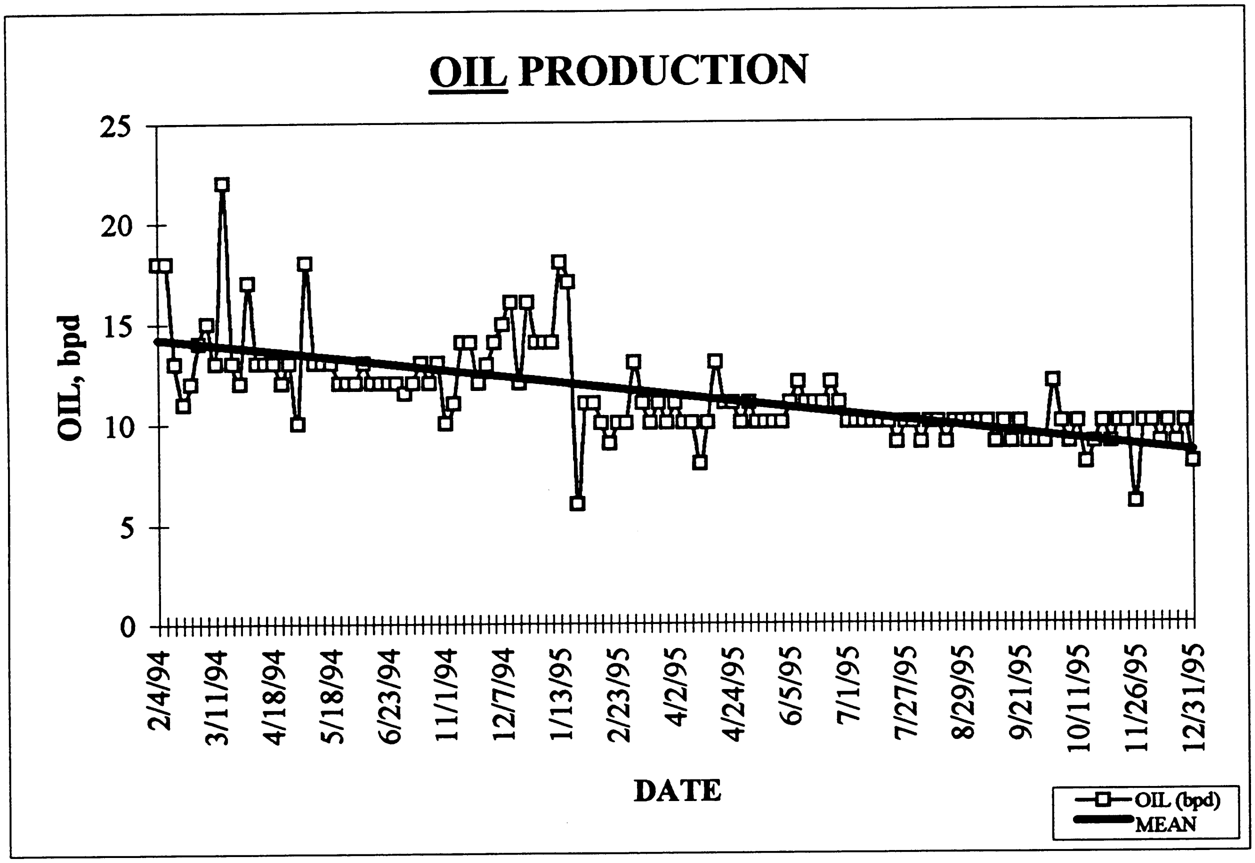


Fig. 16- PERFORMANCE OF PATTERN 1 CONTROL WELL 2-3 No.1



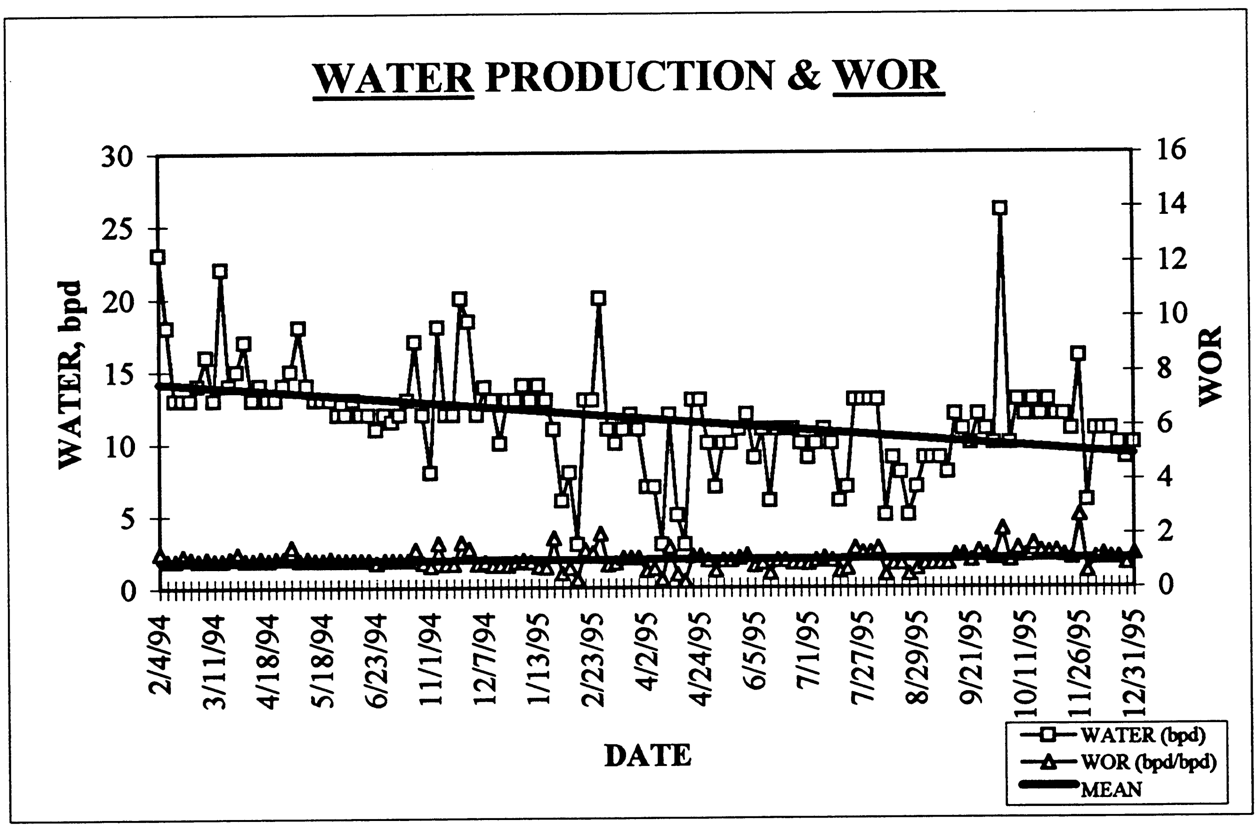
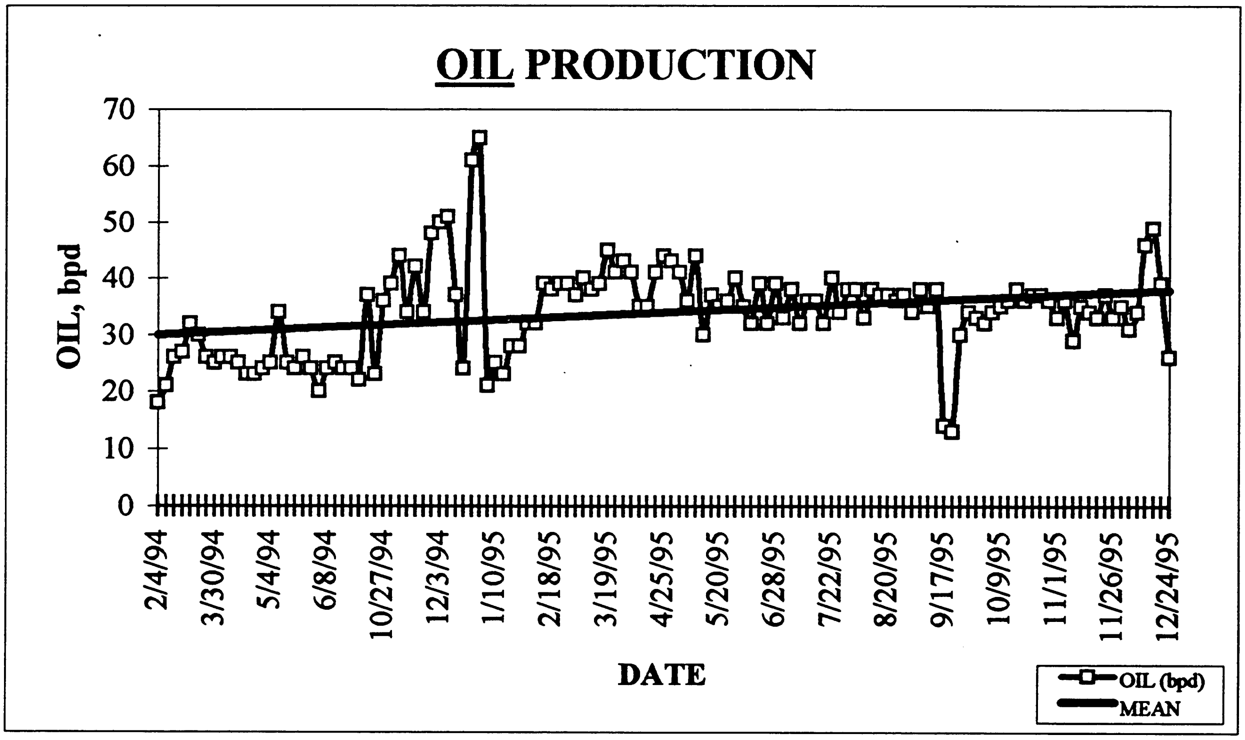


Fig. 17- PERFORMANCE OF PATTERN 1 CONTROL WELL 2-5 No.1



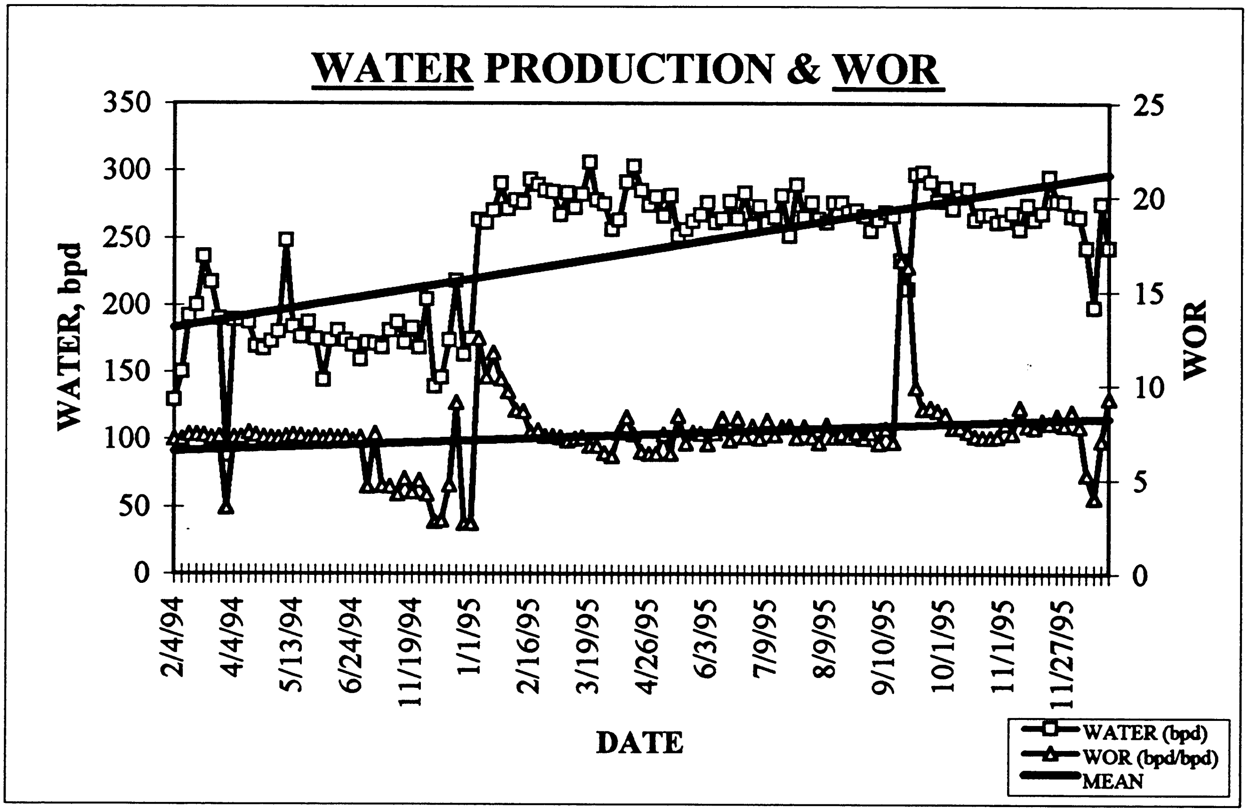
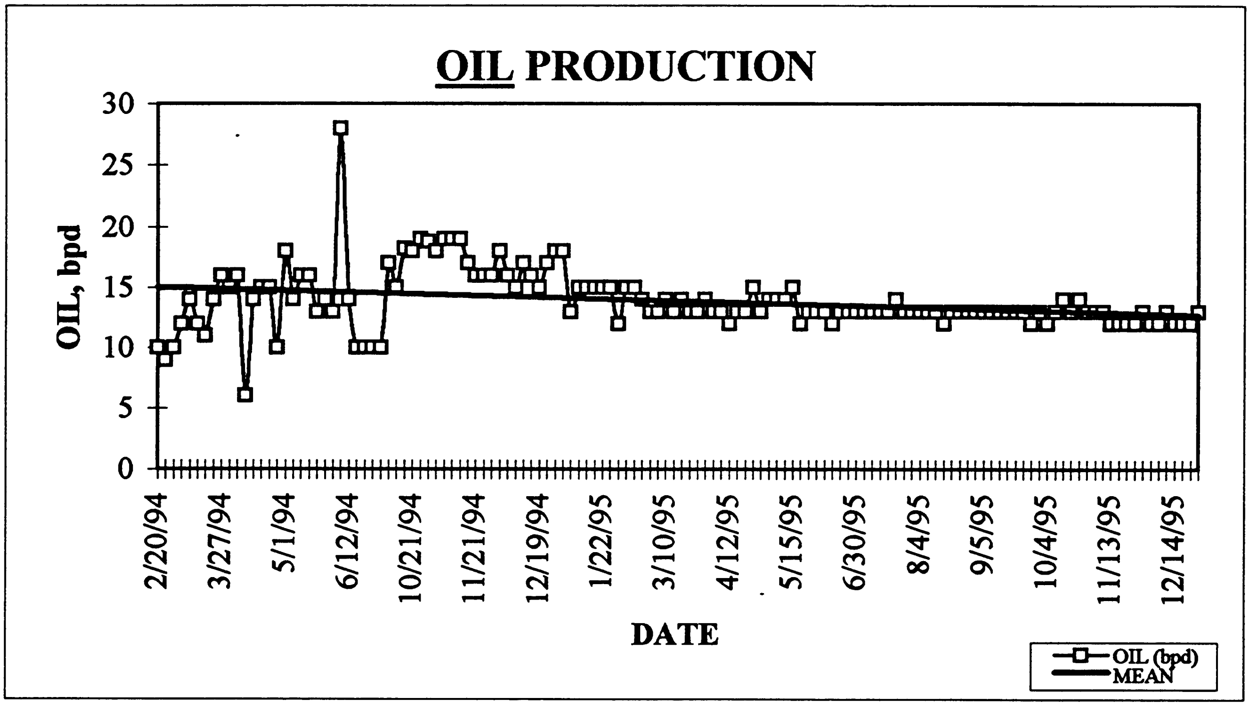


Fig. 18- PERFORMANCE OF PATTERN 1 CONTROL WELL 3-1 No.1



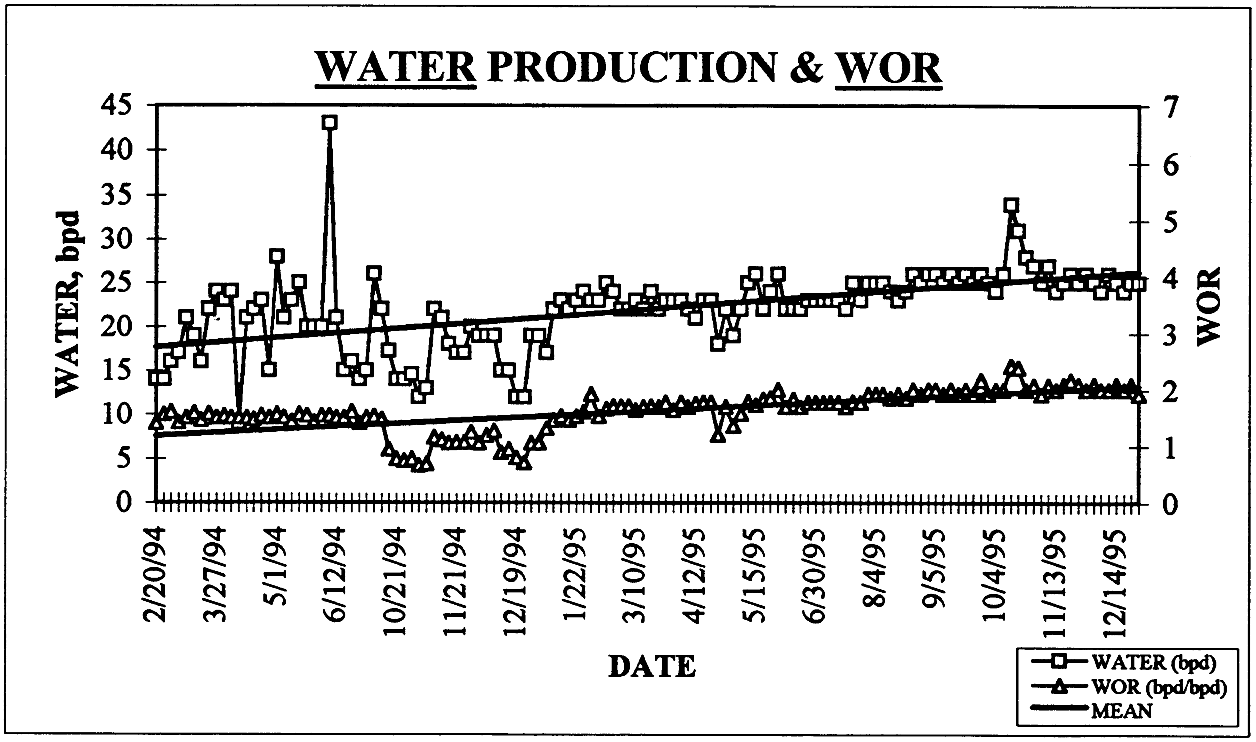
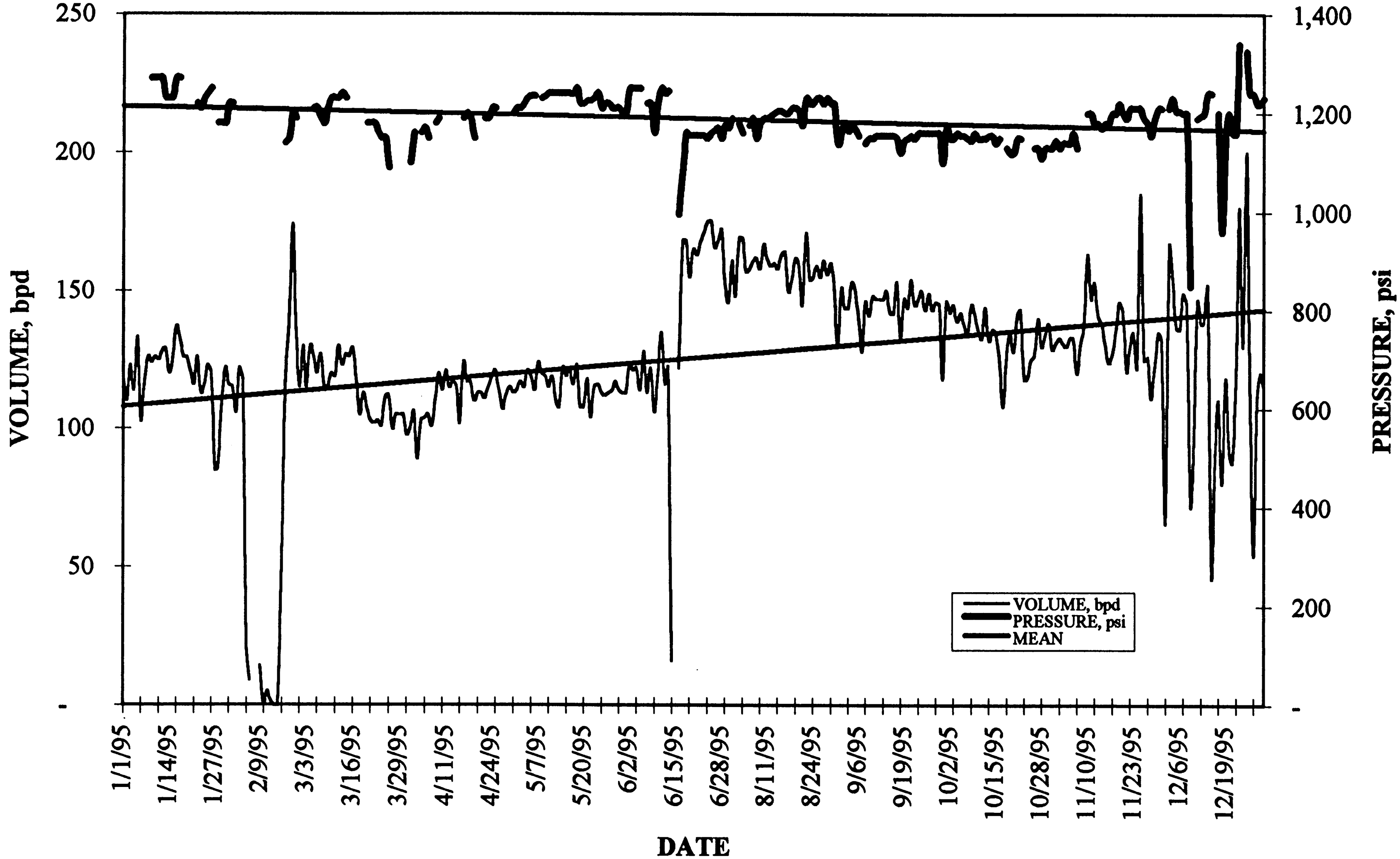


Fig. 19- HISTORY OF WATER INJECTION FOR PATTERN 1, CONTROL WELL 2-4 No.1



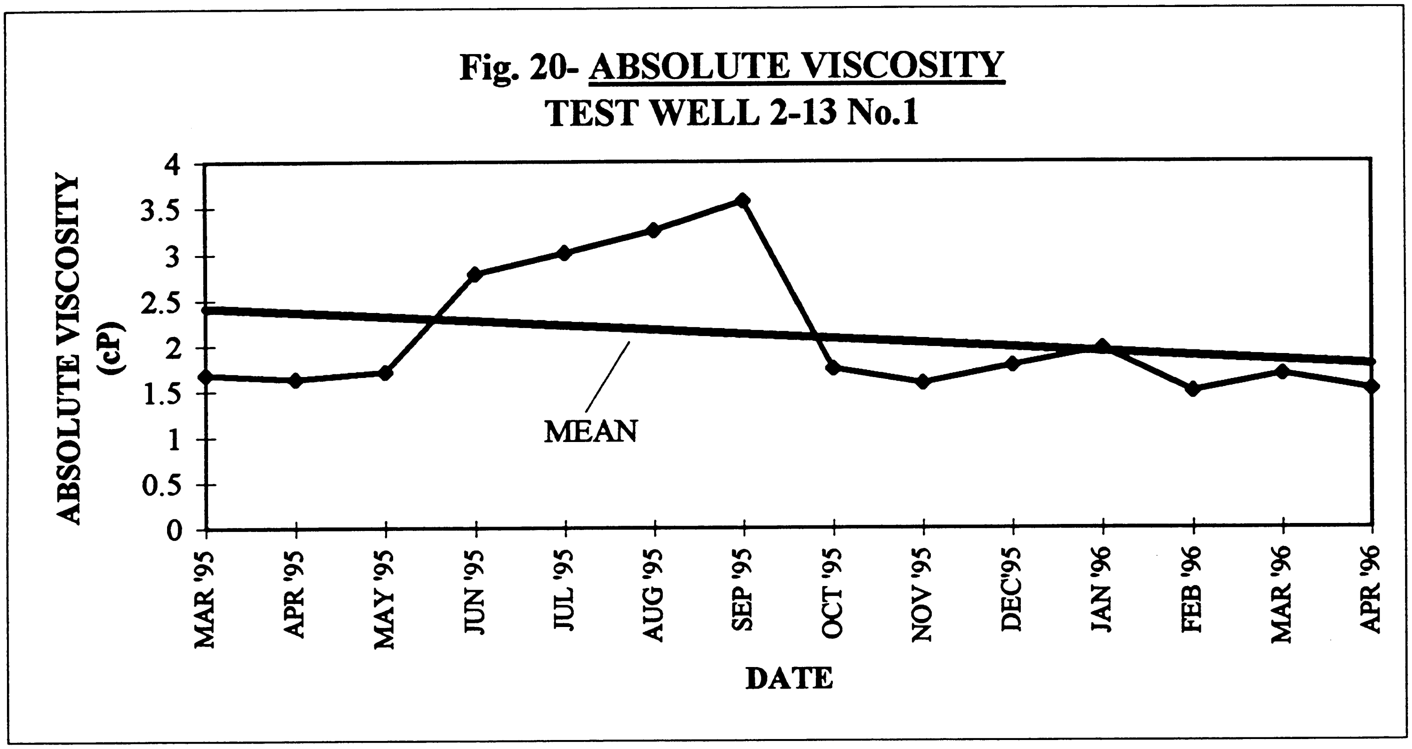


Fig. 20- ABSOLUTE VISCOSITY
TEST WELL 2-13 No.1
ABSOLUTE VISCOSITY (cP)
4
3.5
3
2.5
2
1.5
1
0.5
0
MEAN
MAR '95
APR '95
MAY '95
JUN '95
JUL '95
AUG '95
SEP '95
OCT '95
NOV '95
DEC'95
JAN '96
FEB '96
MAR '96
APR '96
DATE

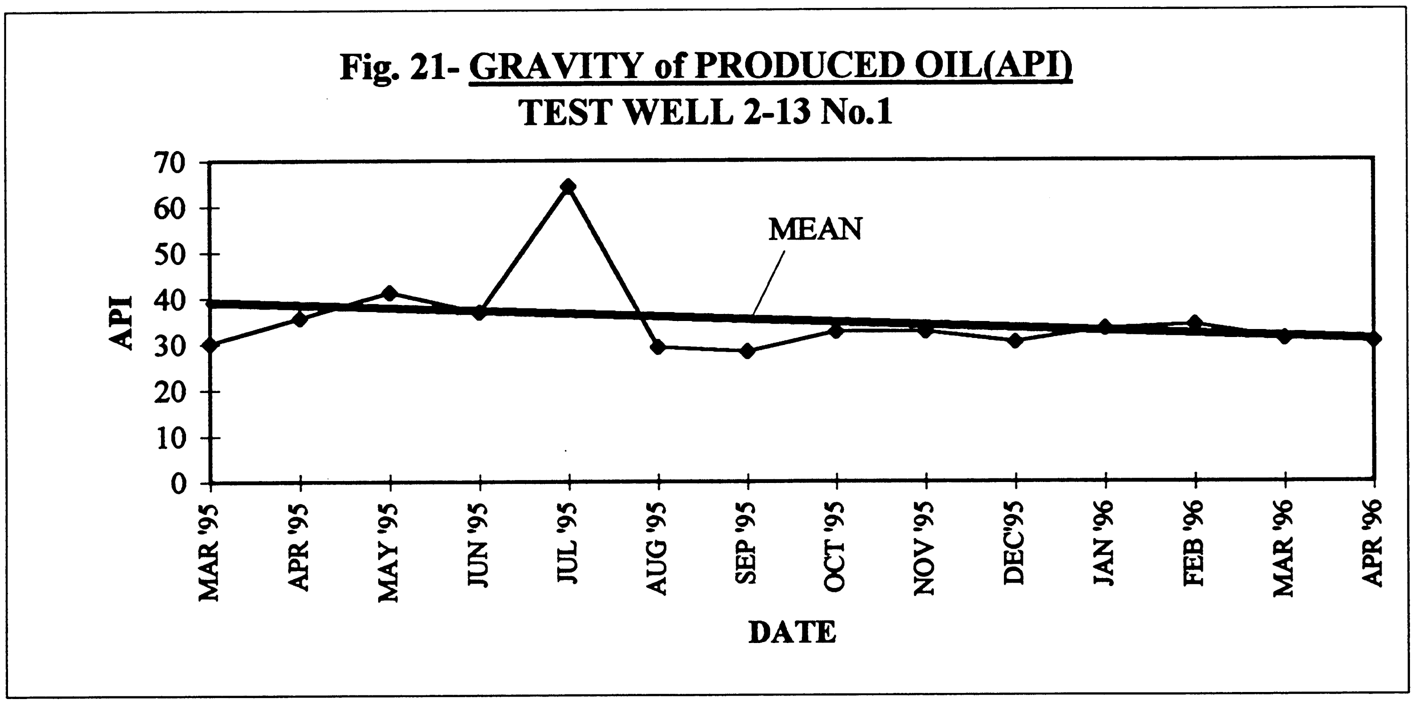


Fig. 21- GRAVITY of PRODUCED OIL(API)
TEST WELL 2-13 No.1
API
70
60
50
40
30
20
10
0
MEAN
MAR '95
APR '95
MAY '95
JUN '95
JUL '95
AUG '95
SEP '95
OCT '95
NOV '95
DEC'95
JAN '96
FEB '96
MAR '96
APR '96
DATE

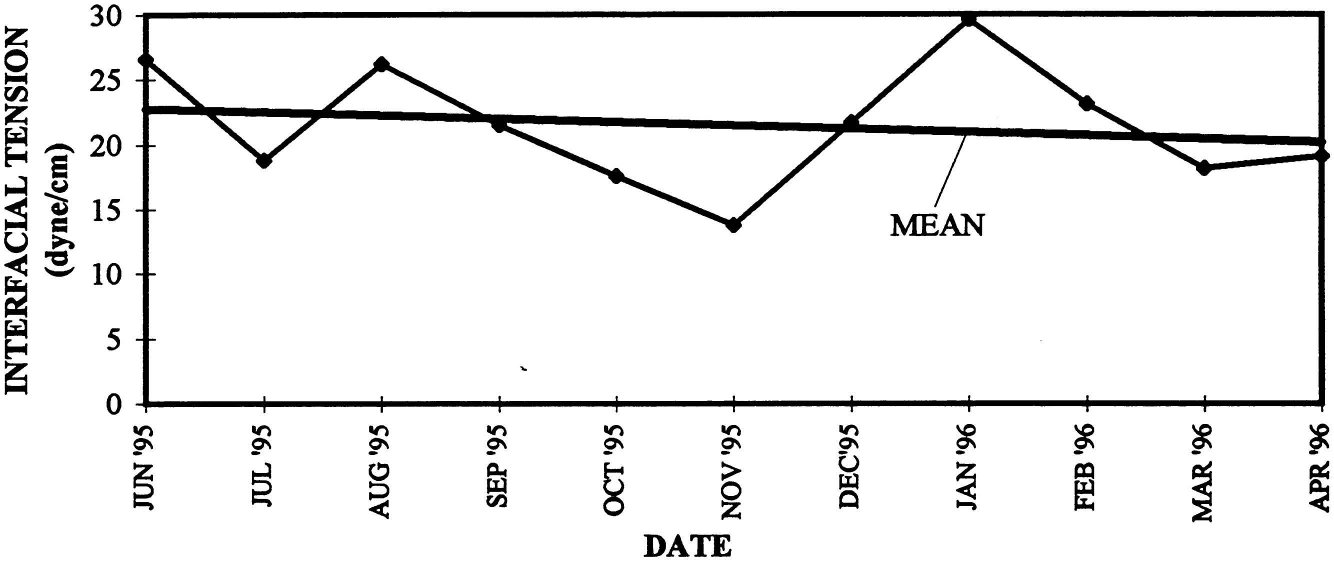


Fig. 22- INTERFACIAL TENSION of PRODUCED OIL-WATER SYSTEM, TEST WELL 2-13 No.1

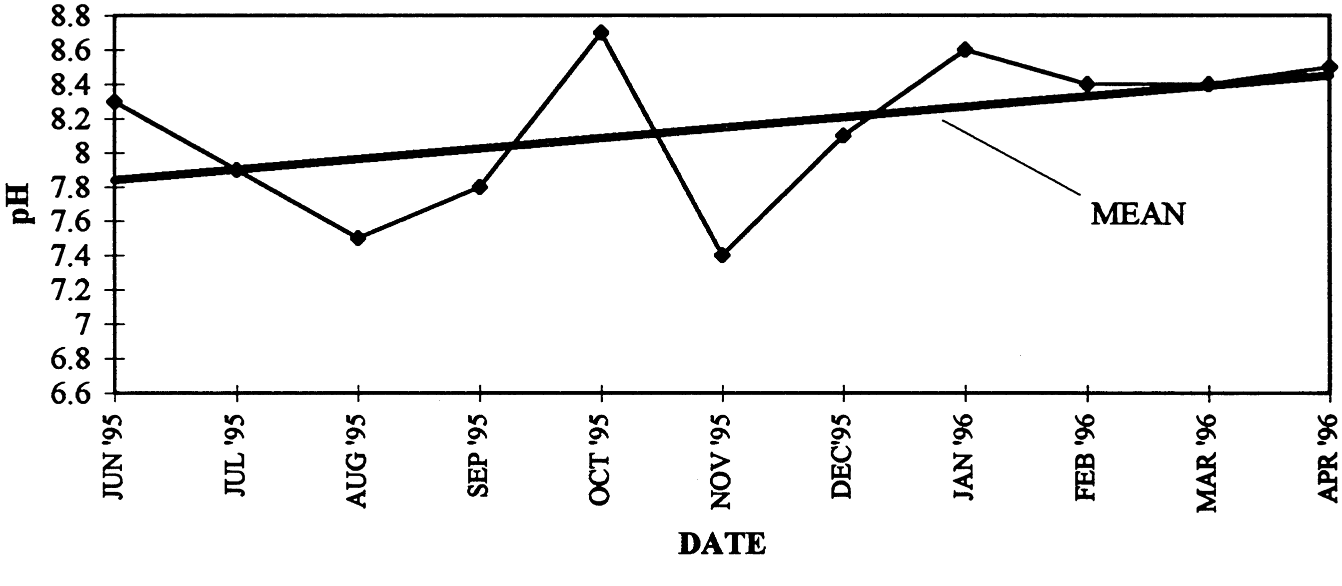
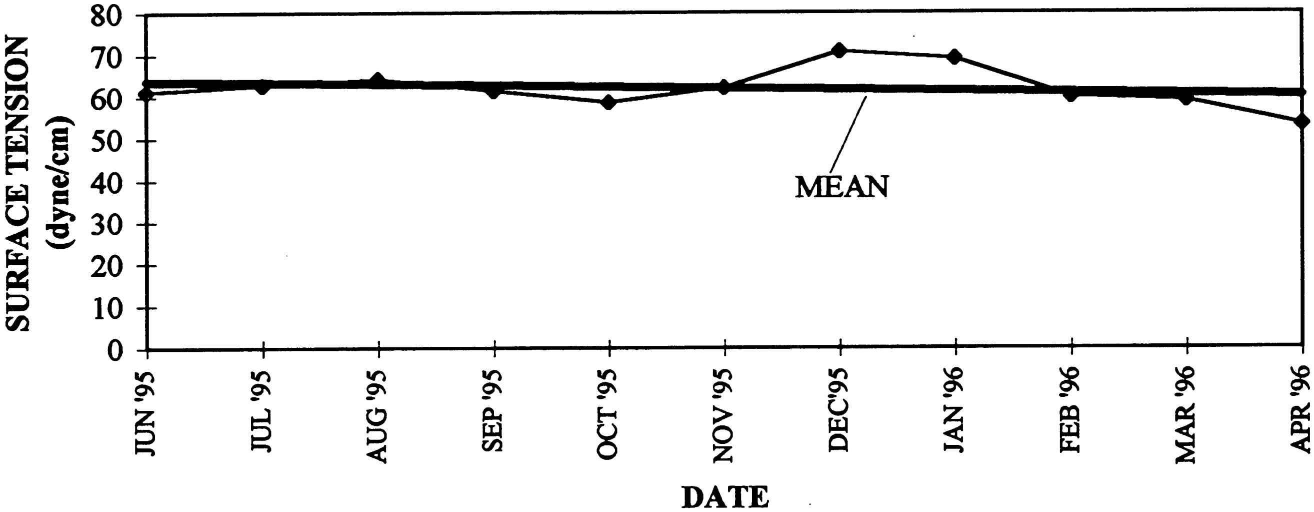


Fig. 23- pH of PRODUCED WATER, TEST WELL 2-13 No.1

Fig. 24- SURFACE TENSION of PRODUCED WATER , TEST WELL 2-13 No.1



Analysis of other data such as aliphatic profile, viscosity, gravity, and pH has not shown any definitive change at this time.

It is significant to note that after over one year of injecting special microbial nutrients into the formation, there is no evidence of well plugging in the injector well and also there is no evidence of injected nutrients in produced fluids as yet. Field nutrient injection of this project is 30% complete and it is expected to continue for another two years before the final results are available.

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5. ZoBell, C.E., 1953. Recovery of Hydrocarbons. U.S. Pat., 2,641,566.

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