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A FIELD EXPERIMENT OF STEAM DRIVE WITH IN-SITU FOAMING

Annual Report For the Period October 1, 1982—September 30, 1983

By
William E. Brigham

June 1984

Work Performed Under Contract No. AC03-80SF11445

Stanford University Petroleum Research Institute
Stanford, California

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A FIELD EXPERIMENT OF STEAM DRIVE
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ANNUAL REPORT

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1. INTRODUCTION

Steam injection is the most commonly used enhanced oil recovery process for heavy oil recovery. In the United States, steam drive is often used in California where reservoir conditions of high oil viscosity, low pressure, shallow depth and high oil saturations are favorable to thermal recovery techniques. Since steam is lighter than il it has a tendency to flow through the structurally higher parts of the reservoir; this is known as gravity segregation. Also, because the mobility of the steam is much higher than the mobility of the oil, steam tends to channel through the high permeability zones. Gravity segregation and channeling cause early steam breakthrough to the producing wells and lower the sweep efficiency; consequently, the actual recovery of oil by steam drive is considerably less than the amount potentially recoverable by this process.

The efficiency of steam drive operations can be improved through the use of additives that decrease the mobility of steam through the zones of the reservoir that have already been depleted of oil and divert the steam to unswept areas. Surface active materials can also improve the recovery by reducing the residual oil saturation. This is accomplished by lowering of interfacial tension between oil and hot water produced by steam condensation and/or modification of wettability of the reservoir. Both mechanisms can be present in a project using steam with additives.

One of the research projects of the Stanford University Petroleum Research Institute[2-7] (SUPRI) is aimed at improving the efficiency of steam injection operations by the use of additives to reduce gravity override and channelling. The project began in 1976; at this time Marsden _et al._[2] (1977) reviewed the literature on mobility control agents and concluded that foam was best suited for this purpose.

Foam is a gas-liquid emulsion. In order to create and propagate a stable foam, a surface active material (surfactant) must be added to the liquid phase, generally water. In addition, to be effective in the mobility control of a steam drive, a foam has to meet the following requirements:

1) The foam must be stable at relatively high temperatures.
2) The foam must preferentially penetrate the steam swept zones and reduce their permeability.
3) The "blocking "action should persist for an extended period of time under reservoir conditions.

A laboratory study was initiated to evaluate the temperature stability of foaming agents (surfactants) and to characterize their flow properties in porous media. One of the goals of that study was to select from the numerous commercial surfactants those that are potentially applicable in steam drive with foam. The screening process involved several stages. Preliminary screening was conducted by boiling surfactant solutions of various concentrations mixed with varying amounts of salts and crude oils at 212°F(100°C) [Elson and Marsden[3], (1979)]. To reduce the possibility of oxygen from the air reacting with the mixtures, nitrogen was slowly bubbled through the solutions. The height of the resulting foam column and the foam characteristics were observed for one week. Only one-third of the surfactants tested were still foaming at the end of the period.

The surfactants that passed the test were then tested at typical steam injection temperatures and pressures through a one-dimensional sandpack in a tube furnance [Owete _et al._[4], (1980)]. The pack was saturated with the surfactant solution, subjected to steam injection conditions and then nitrogen was injected from one end. The observed mobility reduction of nitrogen and the delay in breakthrough were taken as criteria for permeability blocking. For the foamers that passed this test, the process was repeated with the pack containing oil with irreducible water saturation. A slug of foamer followed by nitrogen was injected into the pack. The experiment lasted from 2 to 5 hours at 350° (176°C) to 400°F (204°C), and the effect of slug size on permeability blocking was studied.

Surfactants were also subjected to steam injection conditions [500 psi and 450°F(231°C)] in pressure vessels under a nitrogen cushion for several weeks to test their longevity [Al-Khafaji _et al._[5] (1980)]. Surface tension, surfactant concentration, pH and conductivity were monitored. Sand, crude oil and inorganic salts were added to the vessels to simulate field conditions.

Mobility control by foaming agents was investigated in a two-dimensional, vertical plexiglass model holding a 4ft x 1ft x 0.25in sandpack [Chiang _et al._[6](1980)]. An injection well at one end and a production well at the other allowed the simulation of flow through a vertical slice of reservoir. Saturation of the sandpack by a surfactant solution instead of pure water sharply increased liquid recovery and breakthrough time in the nitrogen flooding process. The improvement in production was shown to be due to a reduction in gravity override caused by in-situ generation of foam at the gas-liquid interface.

Experimentation at SUPRI[7] thus showed that (1) gravity override of injected gases in gas-drive processes could be sharply reduced; hence, recovery increased by in-situ generation of foam; (2) Suntech IV, a surfactant developed by Suntech Corporation under U.S. Department of Energy (DOE) funding, was a suitable foamer for steam drive enhancement; and (3) several other foaming agents have since been shown to have good thermal stability and mobility reduction characteristics.

Suntech IV is a sulfonate with an equivalent weight of 427. In general, sulfonates used in oil recovery are prepared by reaction of an aromatic nucleus in a hydrocarbon with a reagent which introduces the sulfonate group [Malmberg and Burtch[8](1979)]. Suntech IV is produced by first reacting n-C_{15-18} with toluene. Sulfonation is then achieved by using sulfonic acid followed by neutralization.

Because there are many differences between an idealized laboratory model and an actual reservoir, a controlled and monitored field experiment was planned to test the efficiency of Suntech IV in improving steam drive recovery. The field experiment was to be supported by adequate laboratory research and reservoir engineering.

The SUPRI field experiment is located on the McManus Lease of the Kern River field near Bakersfield, California (Fig. 1). Petro-Lewis Corporation is the operator of this lease. The Kern River field, which was discovered in 1899, covers 9435 acres. Cyclic steam recovery was initiated in the Kern River field in 1961 and steam drive in 1962. The McManus Lease, which is developed on a 2.25 acre five-spot pattern, is undergoing continuous steam injection.

In September 1980, DOE contracted Stanford University to conduct a field experiment on steam drive with Suntech IV. The Stanford University Petroleum Research Institute is responsible for the planning and implementation of this field experiment. Project management and reservoir engineering are subcontracted to GeothermEx, Incorporated of Richmond, California; field services are subcontracted to Chemical Oil Recovery Company (CORCO) of Bakersfield, California. SUPRI provides support services in laboratory research and reservoir engineering.

FIELD WORK COMPLETED TO DATE

2.1 REVIEW OF PAST EFFORTS

A description of the preliminary assessment of the reservoir and of the geological considerations for the choice of the test and the control pattern was given in the first report for this project [Brigham *et al.*[1] (1983)]. The geometry of the field is shown on Fig. 1. The test injector is Well 208 and the control injector is Well 214. The corresponding observation wells (208 M and 214M) were drilled in August 1981. Details of the drilling, coring, logging and completions are also given in the previous report[1].

2.2 WELL TO WELL TRACER TESTING

Radioactive Tracers

To help define the reservoir, a radioactive tracer survey was conducted during November of 1981. Tritium, krypton 85, sulfur hexafluoride and Freon 14 were injected into Well 208 while tritium and krypton 85 were injected into Well 214. As an experiment the U. S. Geological Survey ran a spectral gamma ray log in the observation wells during the injection of krypton 85 to try to monitor the flow of krypton 85. No response was detected; this was probably because of the small amount of radioactive material that could be injected under California law.

Samples were taken from the producers surrounding the two patterns in which the tracers had been injected. These samples were analyzed by Teledyne Isotopes. The following is a summary of the results of this test:

- Tritium and Freon 14 were not detected in any of the producers. The probable reason for this is that the amount injected was insufficient or the sampling procedure was initiated too late, thus missing the breakthrough.
- Krypton 85 and sulfur hexafluoride behaved in a similar manner. Both were observed in Well 120 and in a smaller amount in Well 119.
- Through an oversight no samples were taken from Well 114. This well is the most updip of the test pattern and as shown by the results of inorganic tracer tests was expected to be the most affected by the steam injected into Well 208.
- Analysis of the data from Well 120 is being performed using the technique developed at SUPRI[9].

Inorganic Tracers

Due to the small amount of data obtained from the radioactive tracer survey it was decided to perform a survey using sodium bromide and sodium nitrate as tracers. These non-volatile chemical tracers were observed in the producers. The results show a strong response in the most updip wells (Wells 114 and 126). However, a quantitative analysis of the breakthrough curves was found impossible. Other tests using the same chemicals were performed after injection of the surfactant. Qualitative interpretation of these tests will be detailed in the section on results.

2.3 INJECTION PROGRAM

The injection program consisted of two preliminary tests to verify the feasibility of the process in the Kern River field and of three larger slugs of surfactant for the test itself. The injectivity tests and their results were discussed in the first report. Details of the equipment used during the injection program and of the considerations for the rate calculations were also given. Table 1 summarizes the injection program.

Table 1
INJECTION PROGRAM

Preliminary Tests	
December 1981	2330 gal of 15% active Suntech IV at 0.5 gal/mn. were injected without nitrogen . Test failed due to faulty surfactant.
March 1982	1380 gal of 15% active Suntech IV were injected at 0.7 gal/mn. without nitrogen, then 1120 gal of 15% active Suntech IV at 0.8 gal/mm with 100 scf/mm of nitrogen during 6 hours. This was a successful injectivity test.
Main Injection Program	
July 1982	22,000 gal of 15% active Suntech IV were injected at about 1 gal/mn. and 300 000 scf of nitrogen injected in two slugs at 12,800 scf/hr. Test successful despite operational problems.
Oct.-Nov. 1982	22,780 gal of 14% active Suntech IV were injected at about 0.5 gal/mn. Continuous injection of nitrogen at 10 scf/mn during surfactant injection. Test was successful.
Feb.-April 1983	24,645 gal of 14% active Suntech IV were injected at about 0.25 gal/mn. Continuous injection of nitrogen during surfacant injection at 10 scf/mn. Success despite steam generator failures.

The injectivity tests and the first main slug injection have been described in the previous report[1]. The following comments refer only to the last two slugs of injection:

- o Difficulties had been experienced during the first main slug injection because of the formation of a solid crust at the top of the tanks caused by evaporation of water from the surfactant solution. This problem was solved in the subsequent injections by recirculating the surfactant in the storage tanks to ensure an even concentration of surfactant in the tanks. In order to make sure the concentration would be low enough to avoid a recurrence of this problem the surfactant solution was ordered from the manufacturer at a concentration of 14% active by weight instead of 15%. This explains the difference in concentration between the first major slug and the subsequent ones.
- o The second injectivity test (March 1982) showed a clear advantage in the addition of nitrogen as a non-condensible gas to improve the steam surfactant system. During the first major slug injection, nitrogen was injected at a very high rate during a short period of time. Injection had to be interrupted because of the rapid increase in pressure observed. During the second slug, it was decided to inject nitrogen for the duration of the entire test at a slower and better controlled rate.A rate of 10 scf/min was calculated to correspond to about 5% mole fraction of the gas phase of the steam and this was the rate chosen. This amount is comparable to the quantities injected by Dilgren <u>et al.</u>[10] during the field experiment performed by Shell.
- o Surfactant and nitrogen injections were interrupted during periods of no steam injection due to steam generator failure. This prevented the waste of the chemicals and reduced cooling of the injection well during injection periods.

2.4. LOGGING PROGRAM

Table 2 summarizes the logging program. The first report[1] has described the logs run. Interested readers may refer to it for details. The attempt to monitor the saturations through carbon/oxygen logging will be described later in this report.

Table 2
LIST OF LOGS RUN IN OBSERVATION WELLS

	COMPANY
OPEN-HOLE LOGS	
FDC-Cnl Gamma Ray	Schlumberger
Nuclear Magnetic Log	Schlumberger
Electomagnetic Propagation Tool	Schlumberger
Dual Induction-SFL	Schlumberger
Cyberlook	Schlumberger
Spectralog	Dresser-Atlas
Dielectric Constant	Gearhart
CASED-HOLE LOGS	
Dual Spacing Thermal Neutron Decay Time	Schlumberger
Cement Bond	Schlumberger
Gamma Ray Spectroscopy (Well 214M only)	Schlumberger
Carbon/Oxygen	Dresser-Atlas
Temperature	USGS
COMPUTER PROCESSED LOGS	
VOLAN	Schlumberger
Production Management	Schlumberger

2.5. PRESSURE FALLOFF TESTING

Only a brief description of the testing performed will be given because a detailed description is avaliable in the previous report[1]. The results and conclusions will be presented later in this report.

2.6 INJECTIVITY PROFILES

Injectivity profiles were taken in Well 208 (test pattern) before, during and after every slug injection. These profiles are obtained by injecting a water soluble radioactive tracer with the steam and making repeated passes over the perforated interval with a detector. The amount of water entering a given interval of the formation can be calculated from the intensity and the rate of decay of the radioactivity detected. A similar procedure is used for the gas phase, this time using a gas soluble tracer instead of a water soluble one. This type of test can provide good qualitative information on the relative amounts of fluid entering each layer of the formation. However, the procedure for calculating the exact amount of steam or water entering one particular layer is not very well defined mathematically and hence quantitative analysis of such tests should not be attempted. The main interest of this testing technique is to allow an assessment of the effectiveness of diverting chemical near the wellbore. Comparison of the tests made before, during and after the injection of Suntech IV provided useful information. The results are discussed in more detail in Section 3.

3. RESULTS AND CONCLUSIONS TO DATE

3.1 Injection Pressure

The injection pressure in Well 208 was monitored carefully. Figure 2 shows these results for the first main slug. Note the two big spikes. They were caused by a large amount of nitrogen being injected in a very short time. Ignoring these spikes, one can note that injection pressure went from 80 psig to an average of 120 psig during surfactant injection. This increase is too large to be entirely attributed to the additional amount of fluids injected.

Fig. 3 shows the effect of the second slug on the injection pressure. Once again the initial pressure was 80 psig. Injection of surfactant and nitrogen caused an increase from 80 to 150 psig. This increase can be attributed to the blocking action of the foam generated in situ. The steam generator failed for three days during the test. This is reflected by a sharp drop in injection pressure to about 50 psig. After the injection of steam, surfactant and nitrogen resumed, the pressure went back to 150 psig. When the injection of surfactant was terminated the pressure gradually declined to about 110 psig. At this stage nitrogen injection was terminated causing a further 5 psi decline. Injection pressure continued to decline until 30 days after the end of surfactant injection when it reached the initial value of 80 psi and stabilized.

The pressure behavior for the third slug injection was essentially identical except for the fact that numerous interruptions of the steam generation were experienced. However, after every interruption the pressure went back up to 150 psig when surfactant and nitrogen were injected. Post injection decline occurred in a manner similar to the second slug injection. Fig. 4 summarizes these data.

3.2 Temperatures at the Producers

Temperatures at the producers are plotted on Figures 5 through 8. The general trend is a decline of the producing well temperatures during and after surfactant injection. This seems to confirm a diversion of at least part of the steam towards unswept areas of the reservoir. Some of the valleys observed in the curves may be the result of interruptions of steam injection caused by generator failures. It is difficult to perform a detailed interpretation of these data because of scatter in the data taken prior to the test. The variations in temperatures of the producers observed during the test period are in the same order of magnitude as the variations observed before the test. The general decline in temperatures from June 1982 to September 30, 1983 is very clear on Well 119 (Fig 5) and on Well 114 (Fig 6). It is smaller but still present on the other two wells. During this period, no temperature decline occurred in the control pattern.

3.3 Injection Profiles

The procedure for injection profiles and the results obtained from profiles taken during the first slug injection have been presented in the first report. The injection behavior followed the same pattern for the last two slugs, namely a marked improvement of the injection profile of both water and steam phases when injecting the surfactant nitrogen combination. Our pilot pattern is atypical because prior to the treatment of Well 208 most of the steam injected went into the fourth sand layer at the bottom of the well. This was caused by additional perforations in this zone. During the treatment, injectivity in that zone was reduced and previously unswept or poorly swept Layers 1 to 3 were contacted by the steam.

Quantitative interpretation of the data provided by the service companies performing injectivity profiles is difficult because the method of analysis of these tests varies from company to company. However, injectivity profiles can be a very useful tool to qualitatively monitor the steam injection behavior and are worthwhile.

3.4 Tracer Studies.

As discussed in Section 2 the radioactive tracer results were not analyzed, the following describes the results obtained from inorganic tracer tests.

Fig. 9 shows a comparison of the tracer response before surfactant injection and during the second slug injection. Note that the flow patterns have changed and that the relative volume of flow of steam towards Well 113b and Well 119 has increased while the flow towards Well 120 was substantially reduced. The flow of steam towards Well 114 appears almost unchanged.

Tracer data provide further proof that the surfactant nitrogen injection with the steam has indeed diverted the steam towards unswept areas. However, a quantitative analysis of these data is difficult because of the nature of the tracer tests themselves. The mechanisms of the flow of inorganic material with the steam are not well known and hence a detailed analysis is impossible.

3.5 Carbon/Oxygen Logging

It was expected at the start of the project that we could monitor the changes in hydrocarbon saturation fron carbon/oxygen logging in the observation wells. To this end, C/O logs were run in the observation wells every three months. The accuracy of this tool was insufficient to provide monitoring of the changes in saturation. At least in our experiment the carbon/oxygen log seems to be ineffective as a monitoring tool. It is possible, however, that on longer projects or on projects showing very large changes in saturation this tool can be used more effectively. Fig 3.9 is an example of the results obtained in Well 208

3.6 Well Testing

Pressure falloff tests were performed at regular intervals of time in Well 208 and in Well 214. The purpose of these tests was to establish if this is a reasonable method to monitor the steam zone growth. The conclusions presented in the first report[1] remain valid; that is:

- The tests performed in Well 214 can be analyzed and give reasonable results showing steam zone growth.
- The results of tests performed in Well 208 were such that no analysis was possible. The discrepancy between the two wells may be caused by the fact that steam breakthrough has occurred in the producers adjacent to Well 208 hence making several of the hypothesis used in the mathematical formulation of the analysis invalid.[11-12]

3.7 Production Data.

During the course of the field experiment two independent sets of production data were gathered on the test pattern. One set came from the lease operator. The other was collected by CORCO, the field operator for the experiment. A comparison of these two bodies of data showed radically different oil and water production figures for the same wells over the same period of time.

To illustrate the difference please examine Figure 10. It shows the oil production from the 208 test pattern from July of 1981 to September 1983. The dashed line is the CORCO reported production while the solid line is the owner's (Petro-Lewis) figures reported to the California Division of Oil and

Gas (D.O.G.). Figure 11 shows test pattern water production in a similar fashion.

SUPRI has initiated a procedure to verify one set of data or the other. Before discussing this process it would be useful to describe the owner's measurement techniques and data and then contrast it with the CORCO techniques and data.

The current owner has been operating the lease since the middle of 1981. Prior to that time the previous owners had been using two generators to supply steam for the steam drive process. The current owner cut down to one generator shortly after acquiring the property. Steam injection rates, as reported to the D.O.G., fell from a monthly average of 15,000 bbl cold water equivalent (CWBE) per well to 5,500 CWBE between early 1980 and late 1981. This 63% decrease makes direct comparison of production before and after the change difficult. Since the time of reduction, steam injection has remained steady. Consequently, only production after July 1981 is to be considered.

The lease operator has been conducting 24 hour well tests to find the oil and water production from each well. These tests are performed about four to five times a month on each well in the lease. The cumulative oil production indicated by the tests is compared to the actual total oil production measured in the lease stock tank. When these values differ, the well production test figures are adjusted by a "lease factor" so that the tested oil production equals the amount actually produced. This "lease factor" is simply the actual produced oil total divided by the tested produced oil total. Suppose tests indicate Well A makes twice as much oil as Well B. The "lease factor" corrected values for Well A will still be twice that of Well B but the tested oil production will add up to the actual oil production. Essentially, the well tests are used to apportion the stock tank production to individual wells. The "lease factor" corrected values are the ones reported to the D.O.G. by the lease operator.

CORCO determined the oil and water production from a given well by routing the flow line through a vapor separation chamber and then a test meter. Simply described, the test meter was a cylindrical chamber partitioned by several paddles. With each revolution of the paddles a fixed volume of fluid passed through the chamber. The total fluid production (oil and water) was measured by counting the number of paddle revolutions.

Water cut was measured by automatically sampling the contents of the flow line periodically. A sampling port, which squirted samples into a quart collection jar, was located in the center of the cylindrical chamber. The frequency of sampling was adjusted so that the jar was filled up over the period of a 24 hour well test. The contents of the jar were separated into the oil and water components by heating, centrifuging and adding emulsion breakers. The water cut of the sample was assumed equivalent to the water cut of the fluid that passed through the flow line during the period of the test.

CORCO took production measurements on the test pattern wells just prior to the first slug injection in June of 1982 and continuously since then. Until the end of 1982 there were two CORCO testers used at the test pattern. Every few days the testers were switched among the producing wells. Beginning in January of 1983 four testers were employed at the test pattern, allowing daily measurement of oil and water production from each well. The testers were switched between the wells to detect any consistent measurement bias.

The heart of the CORCO tester is the same device employed by the lease operators, namely the cylindrical chamber and sampling port. The preceding description of test metering applies to CORCO's tests, too. One difference is that all the CORCO devices have separators that allow vapor separation before metering and sampling while the operators' meters for Wells 119 and 120 do not. Another difference is that the CORCO testers are portable and have been rotated around the wells to detect any consistent error.

As mentioned before, SUPRI has initiated a third production measurement procedure. This has been done to resolve the discrepancy in production figures. The SUPRI tests, described below, are based on the actual well production collected into a stock tank. It is hoped they will provide benchmark values for comparison with the ongoing operator and CORCO tests.

There are two 500 bbl. tanks (4 bbls. per vertical inch). The production from only one well was diverted into a stock tank for the duration of the test. The wells produced more than 75 bbl per day (oil and water) so 24 or 48 hour tests filled a tank with several feet of production. Direct measurement of gross production was made by observing the fluid level in the tank. Water cut was determined by sampling the produced fluid settled in the stock tank. A 1 $1/2$ inch I.D. sampling tube, constructed from high temperature polyvinylchloride (CPVC), was lowered into the tank. CPVC ball valves at each end of the tube were then closed to trap a column of the fluid. This was emptied into the sample jar. The total volume of the sample was also tested against the measured volume in the tank. The sample was heated, treated with emulsion breaker, and centrifuged to determine the relative volume of water and oil. The tanks were leveled when originally spotted, and several measurements were made around the center, to avoid any error due to tilting.

This procedure, we hope, will provide confirmation of one set of production data. Then, the experiment's effect on production can be examined.

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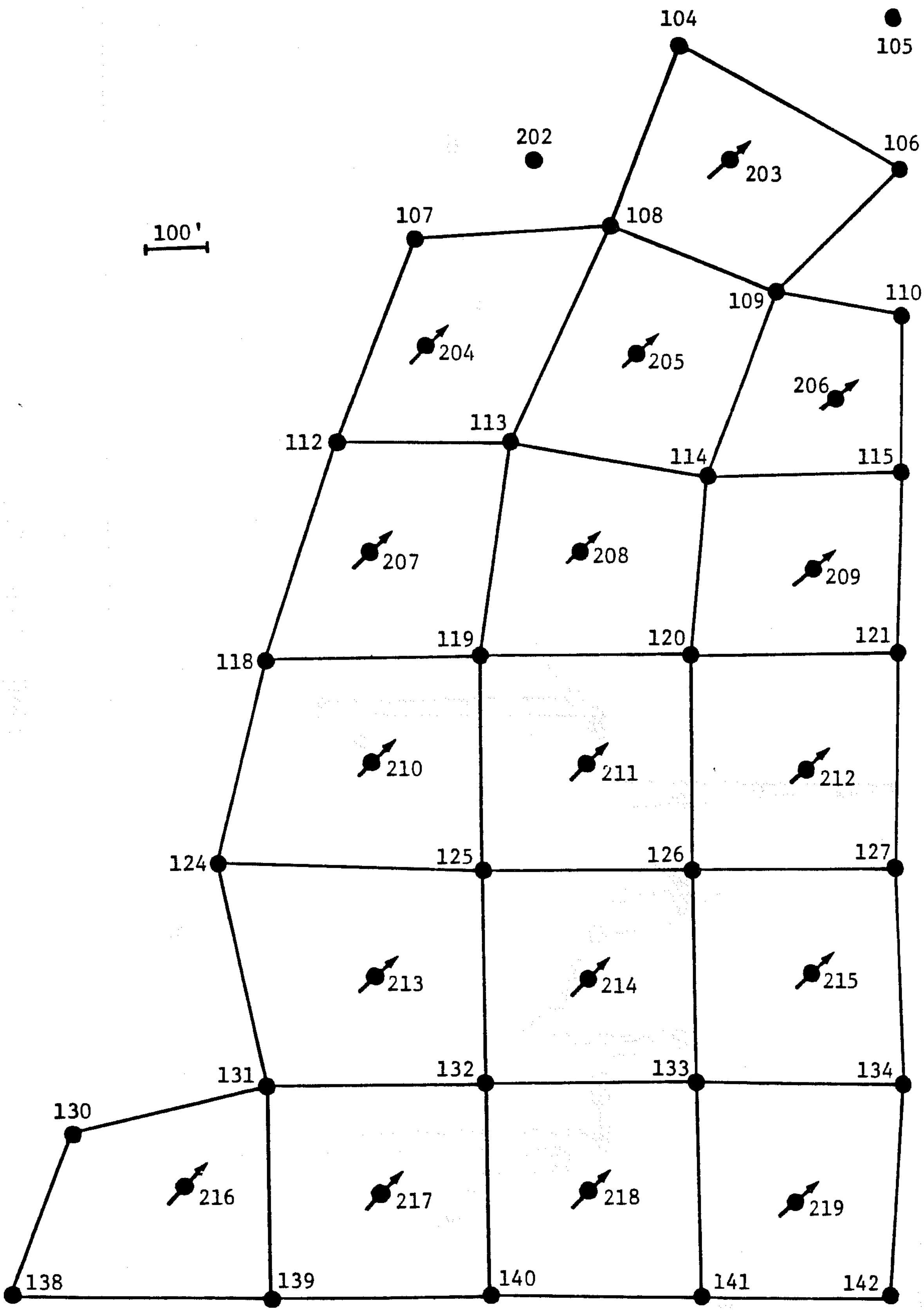


Figure 1. Mc Manus Lease Kern River Field

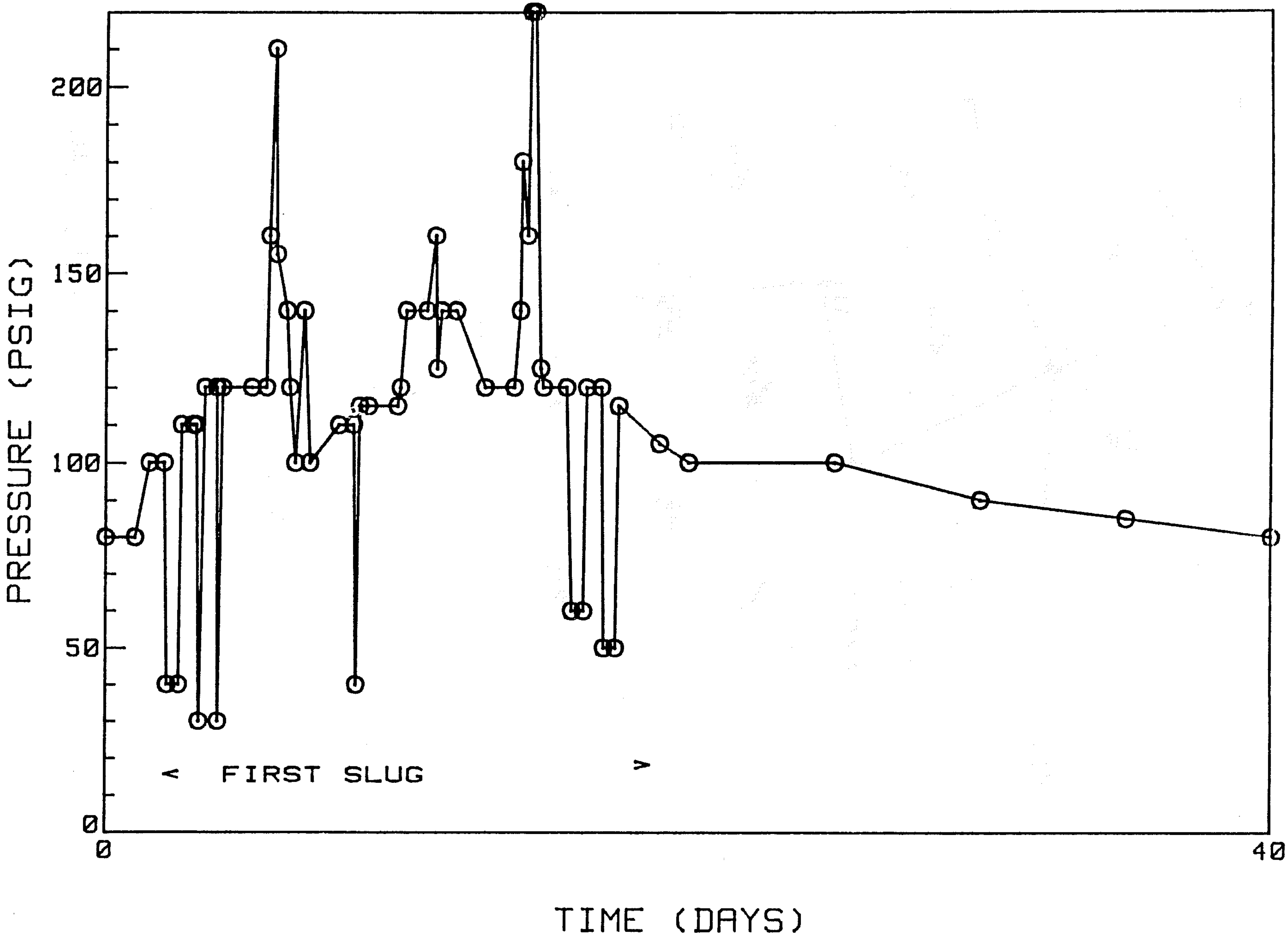


Figure 2. Injection Pressure: First Slug

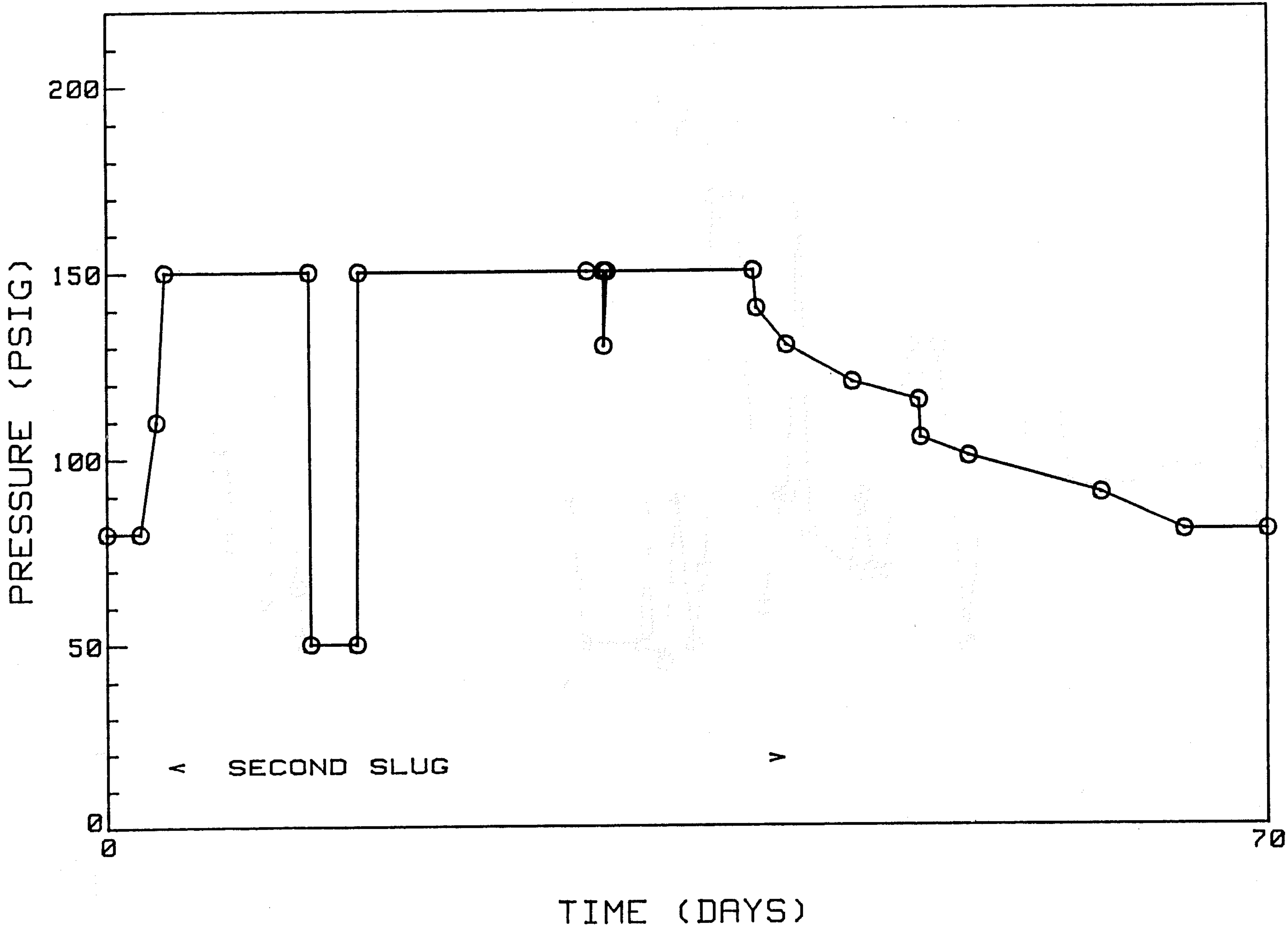


Figure 3. Injection Pressure: Second Slug

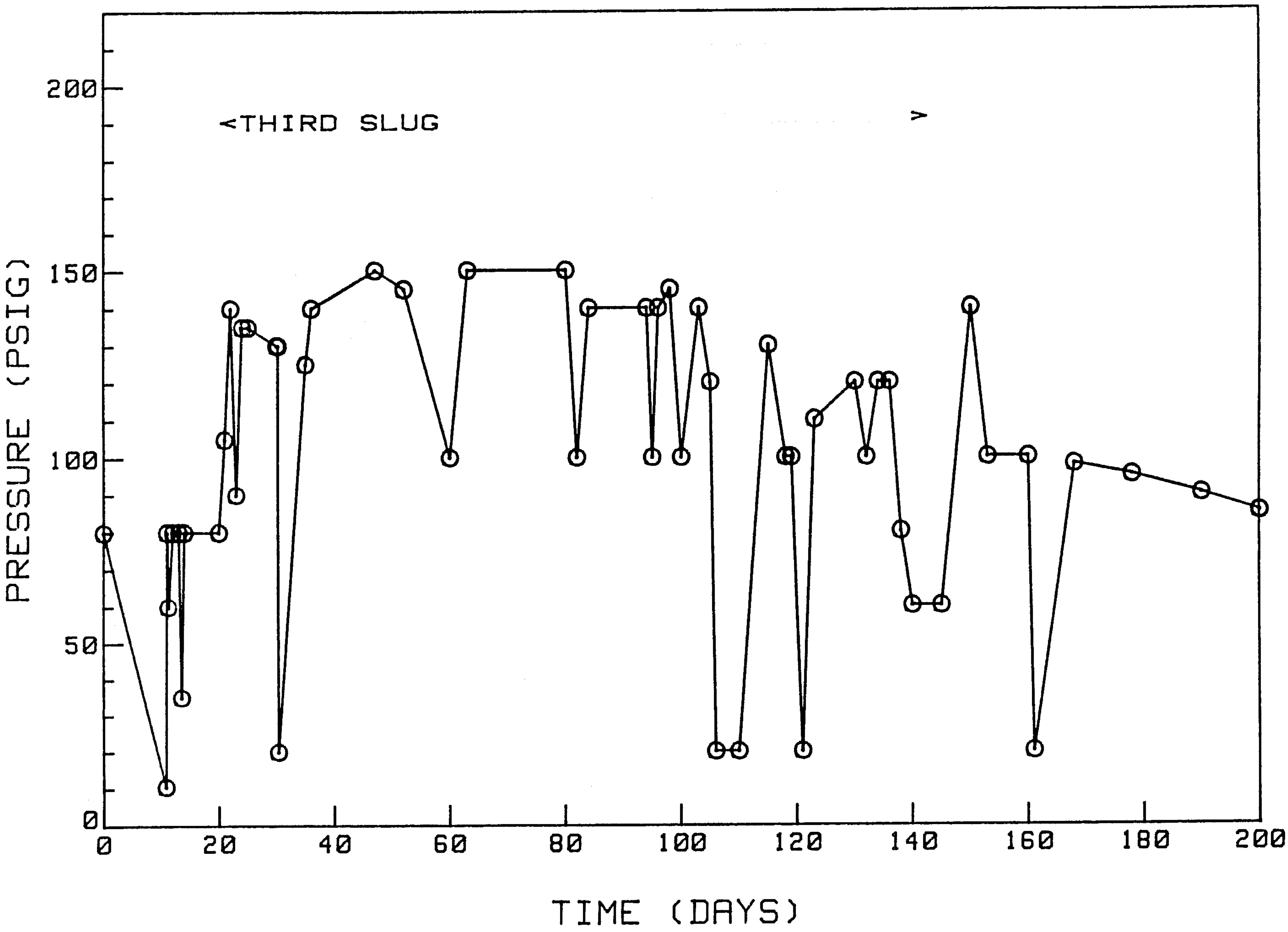
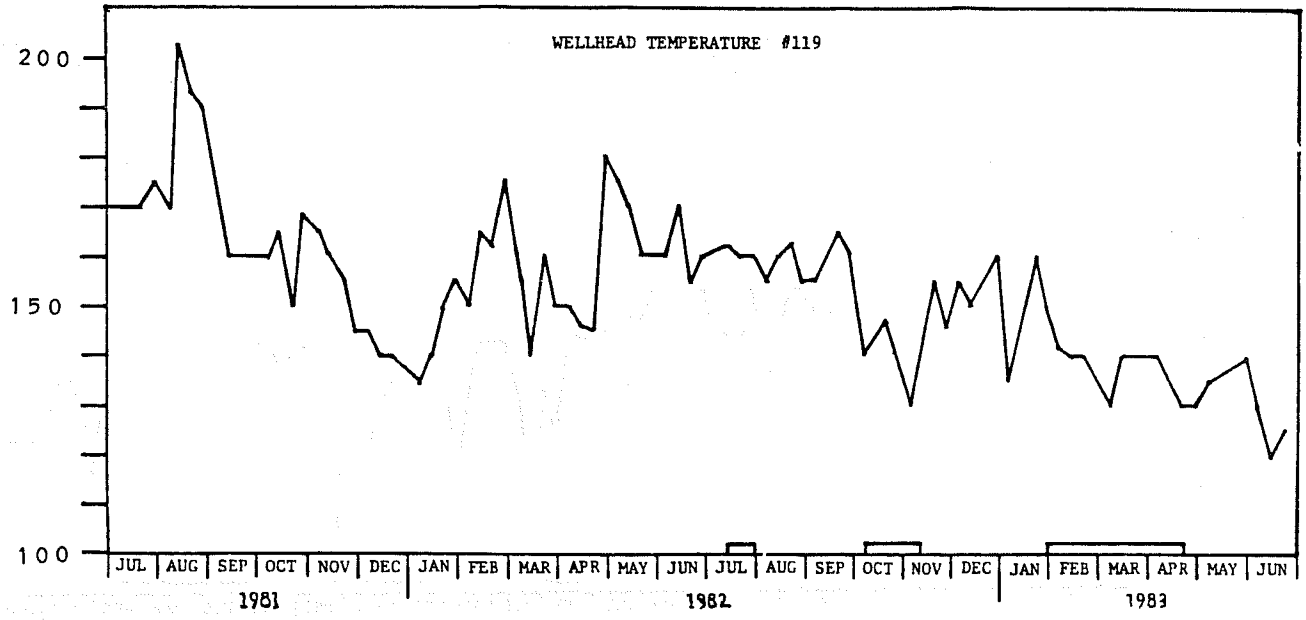


Figure 4. Injection Pressure: Third Slug

Figure 5.



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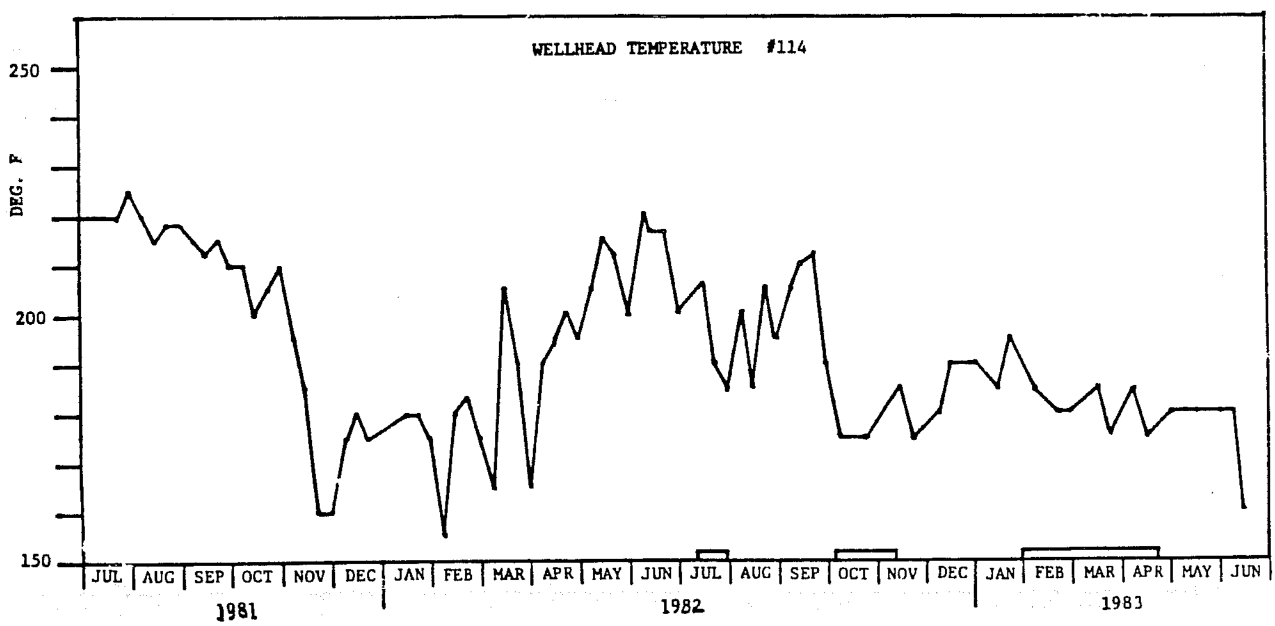

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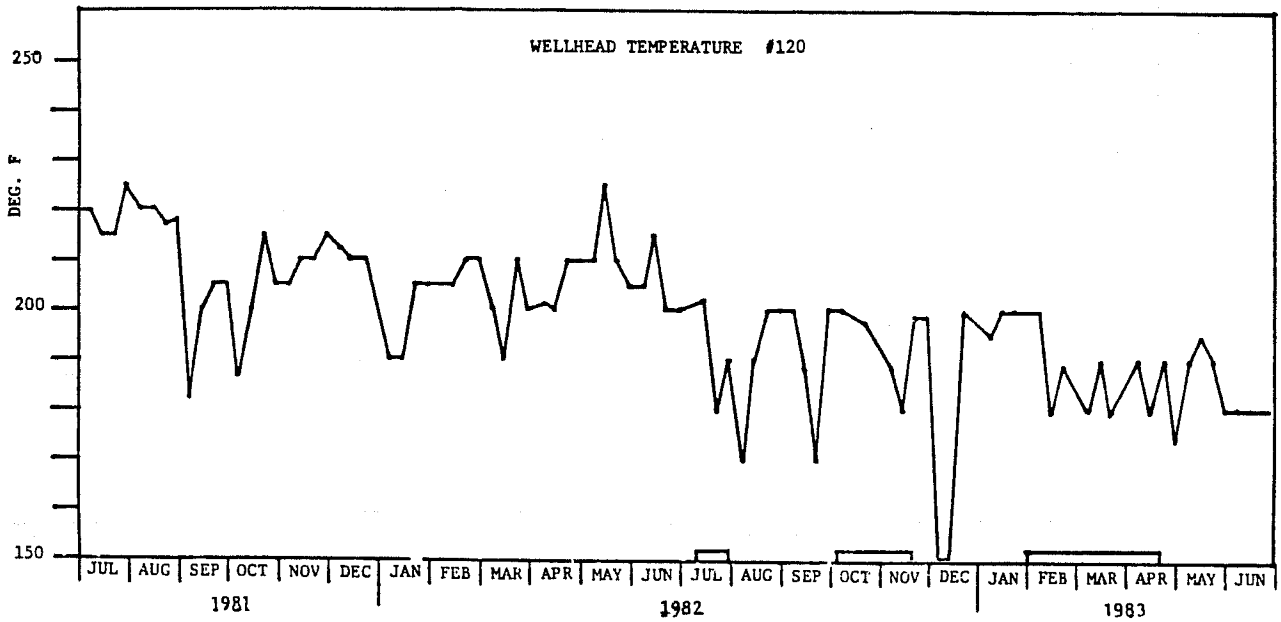

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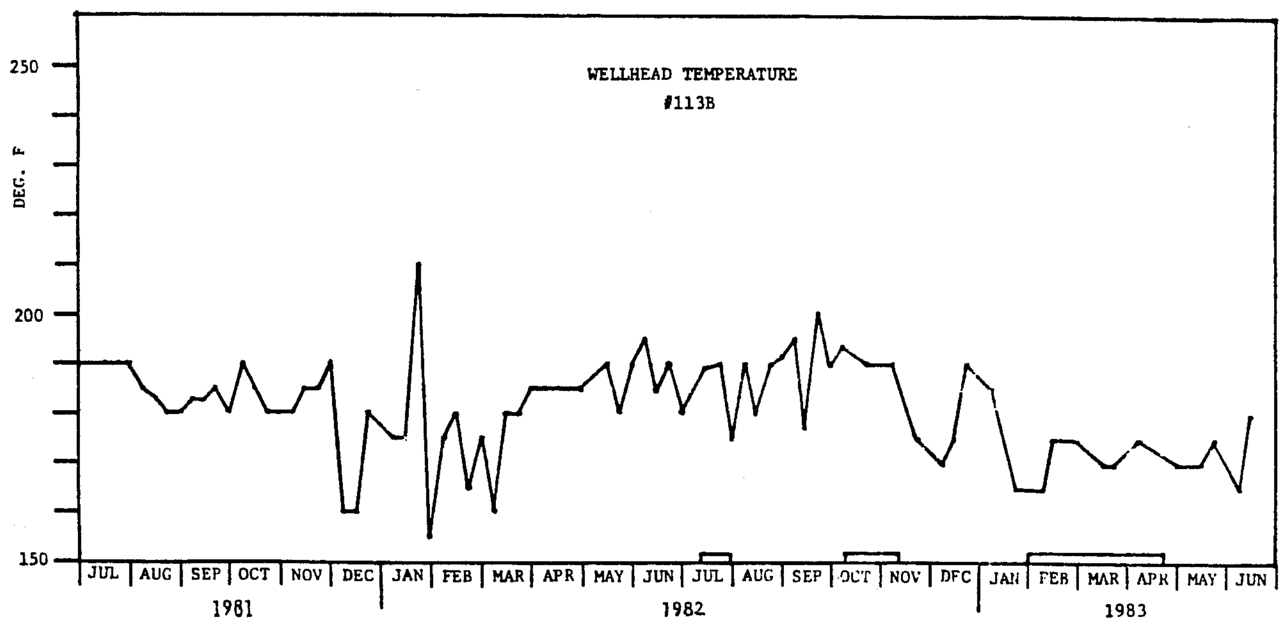

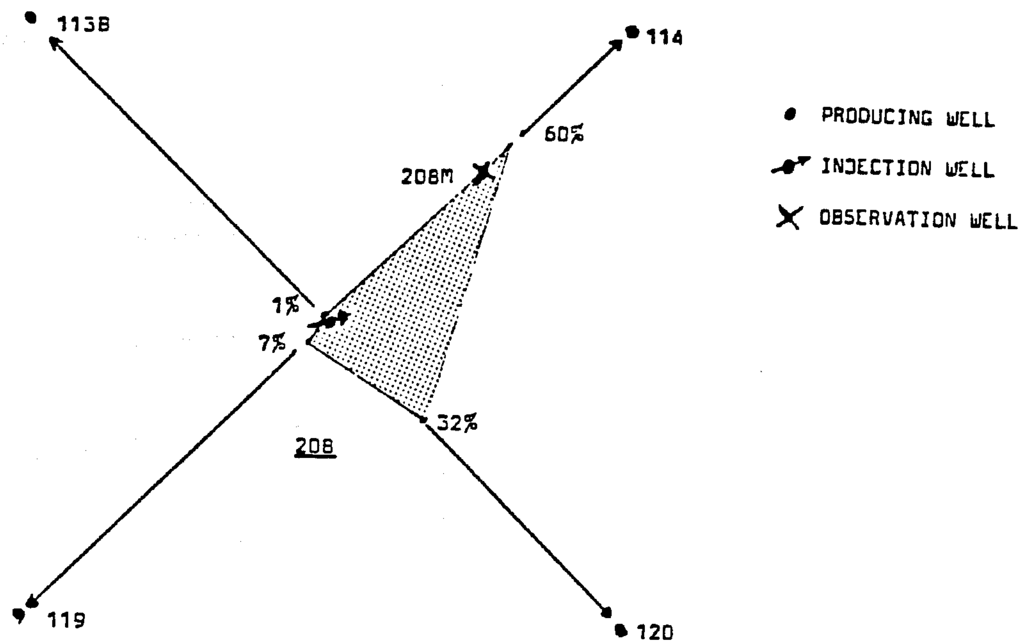

Figure 9a. Inorganic Tracer Results before Injection

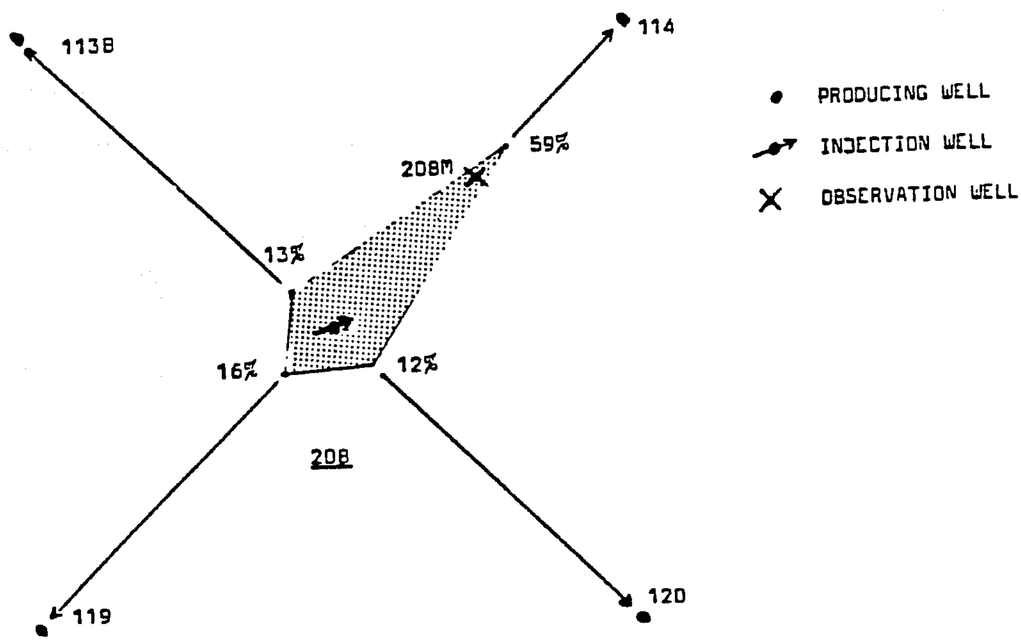

Figure 9b. Inorganic Tracer Results after Second Slug Injection

Figure 10.

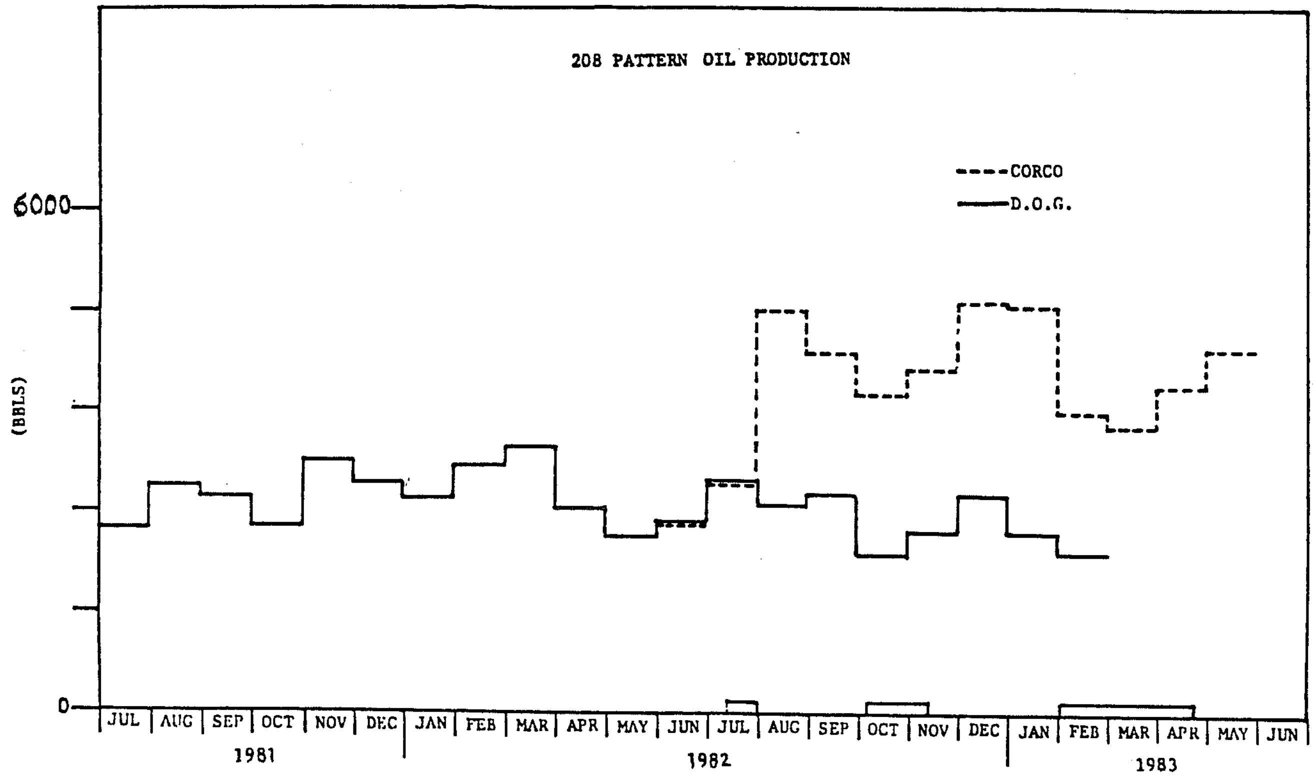

Figure 11.