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A FIELD EXPERIMENT OF STEAM DRIVE WITH IN-SITU FOAMING

Report for the Period October 1, 1980 - September 30, 1982

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A FIELD EXPERIMENT OF STEAM DRIVE WITH IN-SITU FOAMING

REPORT FOR THE PERIOD

OCTOBER 1, 1980 - SEPTEMBER 30, 1982

By

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This research program was carried out under
Department of Energy Contract DE-AC03-80SF11445

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DISCLAIMER

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ABSTRACT

This report discusses the design and execution of a field experiment on recovery of heavy oil by steam drive with in-situ foaming by Suntech IV in the Kern River oil field, California. The project background, goals, and field work completed to date are reviewed. Several standard and experimental analytical methods have been applied to define the reservoir and to monitor the progress of the field experiment. The analysis of the results to date indicate that Suntech IV surfactant shows considerable promise in improving heavy oil recovery by steam drive with in-situ foaming.

1. INTRODUCTION

Steam injection is the most commonly used commercial process for enhanced oil recovery [Enhanced Oil Recovery, 1976]. In the United States, steam flooding is particularly well established in California where reservoir conditions of high oil viscosity, low pressure, shallow depth and high oil saturation are amenable to thermal recovery techniques. Steam injected into the reservoir reduces oil viscosity and improves oil mobility. Since steam is less dense than reservoir fluids, it tends to flow through the structurally higher parts of the reservoir; this is known as gravity segregation. Also, because of its much higher mobility than heavy oil, steam tends to channel through higher permeability zones. Gravity segregation and channeling cause early steam breakthrough to the producing wells; consequently, the actual recovery of heavy 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 higher permeability regions and/or structurally higher parts of the reservoir which have been depleted of oil, and that promote the entry of steam into the relatively unswept parts of the reservoir that are still oil rich.

One of the research projects at the Stanford University Petroleum Research Institute (SUPRI) is aimed at improving the recovery efficiency of steam injection by reducing gravity override and channeling. The project began in 1976; at that time Marsden et al. [1977] reviewed the literature on the applicability of different mobility control agents to the steam injection process and concluded that foam is best suited for this purpose.

To be effectively used as an additive to steam drive, a foam has to fulfill certain requirements:

1) The foam must be stable at relatively high temperatures;

2) The foam must be able to preferentially penetrate deep into the steam swept zones and reduce permeability; and

3) The foaming ability should persist for an extended period of time at 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 [Elson and Marsden, 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._, 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° to 400°F, and the effect of slug size on permeability blocking was studied.

Surfactants were also subjected to steam injection conditions (500 psi and 450°F) in pressure vessels under a nitrogen cushion for several weeks to test their longevity [Owete _et al._, 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 4' × 1' × 0.25" sandpack [Chiang _et al._, 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 thus showed that:

1) Gravity override of injected gases in gas-drive processes could be sharply reduced; hence, recovery was increased by in-situ generation of foam; and

2) Suntech IV, a surfactant developed by Suntech Corporation under U.S. Department of Energy (DOE) funding, was a suitable foamer for steam drive.

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, 1979]. Suntech IV is produced by first reacting $n\text{-}C_{15-18}$ 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 thoroughly 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.

Through 1980, field experiments with in-situ foaming in a stream-drive process in the Kern River area had been attempted with some success. Getty Oil tested

COR-180, a steam-diverter foam, on nine injectors to determine its effect on steam flood oil recovery [Greaser and Shore, 1981]. Radioactive tracer surveys showed that in most of the injection wells, the steam injection profile was improved. Average daily oil production of the test patterns also increased significantly during the foam-test period.

Eson et al. [1981] also tested COR-180 and COR-GEL in four steam injection nine-spots in the North Kern Front field. Field investigation showed that these steam diverter foams altered the steam injection profiles by preventing excessive steam channeling. Early production data indicated a substantial quantity of incremental oil being produced by the four chemically treated patterns.

These field experiments tested the foaming and plugging ability of the surfactant without fully monitored tests or thorough laboratory research and reservoir studies. In addition, none of the field experiments utilized the surfactant Suntech IV, which had been demonstrated by SUPRI to be a suitable foamer for steam drive. During their work, Doscher and Hammershaimb [1981] tested a Suntech product (Sample Code VII) in the laboratory to establish whether the foaming agent was capable of sustaining a foam at reservoir steam temperatures. Before completion of the testing, however, the Suntech surfactant was dropped from further consideration because the foaming agent was not commercially available. It is known that Shell Oil Company has conducted a field test of steam drive with in-situ foaming. However, at the time this report was written, no published reports were available on that pilot.

The SUPRI field experiment is located on the McManus Lease of the Kern River field near Bakersfield, California (Figs. 1.1 and 1.2). Petro-Lewis Corporation is the operator of this lease. The Kern River field, which was discovered in 1899, covers 9435 acres [Kujawa, 1981]. 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 execution 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.

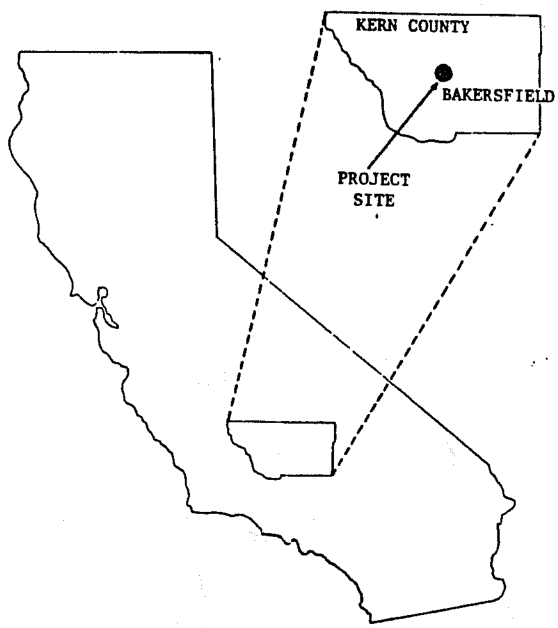


Fig. 1.1: MAP OF KERN COUNTY SHOWING PILOT SITE

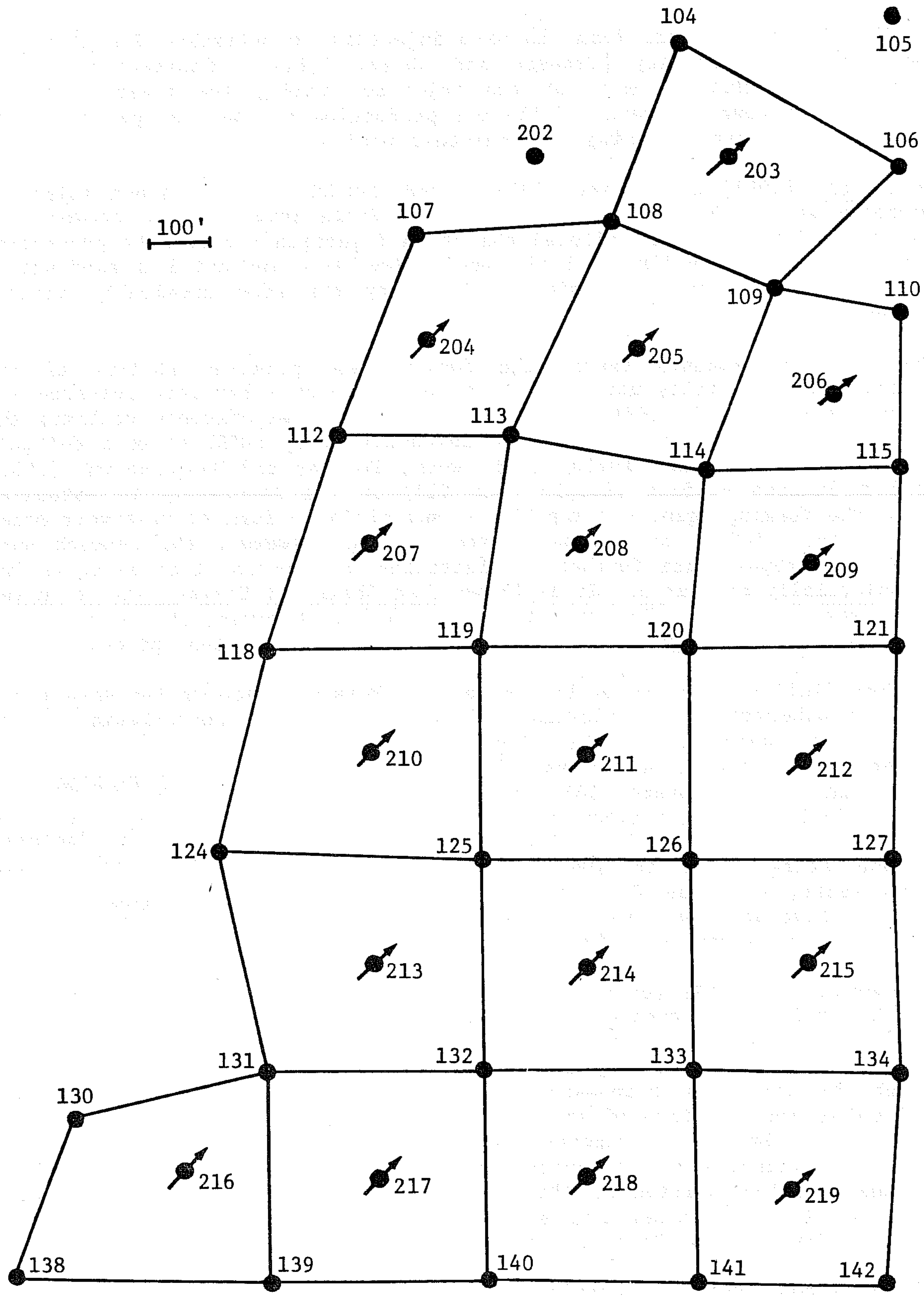


Fig. 1.2: WELL LOCATION MAP

The specific goals of this field experiment can be summarized as follows:

1) Verify that Suntech IV can be used to generate foam in-situ in a heavy oil reservoir under steam drive.

2) Verify that steam drive with in-situ foaming by Suntech IV will show reduced gravity override and channeling in the same reservoir.

3) Verify that in-situ foaming with Suntech IV in a steam drive will increase oil recovery over and above that obtainable by conventional steam drive in the same reservoir.

4) Develop a practical and economical process of handling, storing and injecting Suntech IV in the reservoir.

5) Verify that Suntech IV has sufficient longevity under steam-drive conditions to be applicable in a commercial, field-wide steam-drive project.

6) Evaluate various formation evaluation and reservoir engineering techniques relevant to steam injection and in-situ foaming which are developed at SUPRI.

7) Evaluate, to the extent time and budget permit, various operational options in the steam-foam process, such as injection of an inert gas with steam to improve foaming, effect of surfactant slug size, applicability of various well logs for monitoring, etc.

8) Assess, to the extent results allow, the technical and economic merit of using Suntech IV or a similar surfactant with steam drive to improve oil recovery in a field-wide project.

9) Document all information obtained from this project in technical reports to permit a transfer of technology to operators with similar problems in steam injection.

This study reports the progress of SUPRI's field experiment to test the effectiveness of in-situ foaming as a means of improving heavy oil recovery by steam drive.

2. PROJECT PLAN

2.1 GENERAL PLAN

The time table for the SUPRI field experiment on steam drive with Suntech IV surfactant is shown in Fig. 2.1. The experiment involves an inverted five-spot pattern in which slugs of Suntech IV are added to the steam in test well No. 208 ("Test Pattern"); another inverted five-spot pattern undergoing conventional steam injection into well No. 214 acts as the "Control Pattern" (Fig. 1.2). The two five-spots for the field experiment were chosen based on a preliminary geologic model developed as one of the first steps in the project. One observation well in the test pattern and one in the control pattern were drilled. The core and log data from the observation wells, data from the existing wells, and results of a tracer injection program in both patterns will be analyzed to define the reservoir characteristics.

Evaluation of the experiment will be based on the data to be gathered from the test pattern and the control pattern. The ability of Suntech IV to alter injection profiles in a beneficial manner will be checked by obtaining injection profiles periodically in the test pattern. By repeated logging of observation wells with the Carbon/Oxygen log, changes in oil saturation profile will be monitored. The growth of the steam-swept zone will be monitored by conducting periodic injection pressure fall-off tests and analyzing the data by the technique developed at SUPRI [Eggenschwiller et al., 1980]. Production data, including casing-vent gas analysis, will be used to monitor the steam/oil ratio at the producers. At the end of the experiment, one well will be drilled, cored and logged in each pattern ("Post-Pilot Core Hole").

Once the degree of success in altering injectivity profile and increasing recovery has been established, an economic evaluation will be performed of steam drive with in-situ foaming. The incremental oil produced through the use of surfactant during the steam drive process will be determined through:

1) A comparison of the production data from the control pattern with that from the test pattern;

2) Direct estimate of the extent of incremental desaturation from Carbon/Oxygen log data, post-pilot core holes, injectivity tests and pressure fall-off tests; and

3) A comparison of the actual production behavior of the test pattern with that predicted by simulation for conventional steam drive in the test pattern.

The goal is to estimate a cost per incremental barrel of oil produced. An evaluation of the field data combined with laboratory tests will, it is hoped, define the economics of such an enhanced recovery process in reservoirs with similar characteristics.

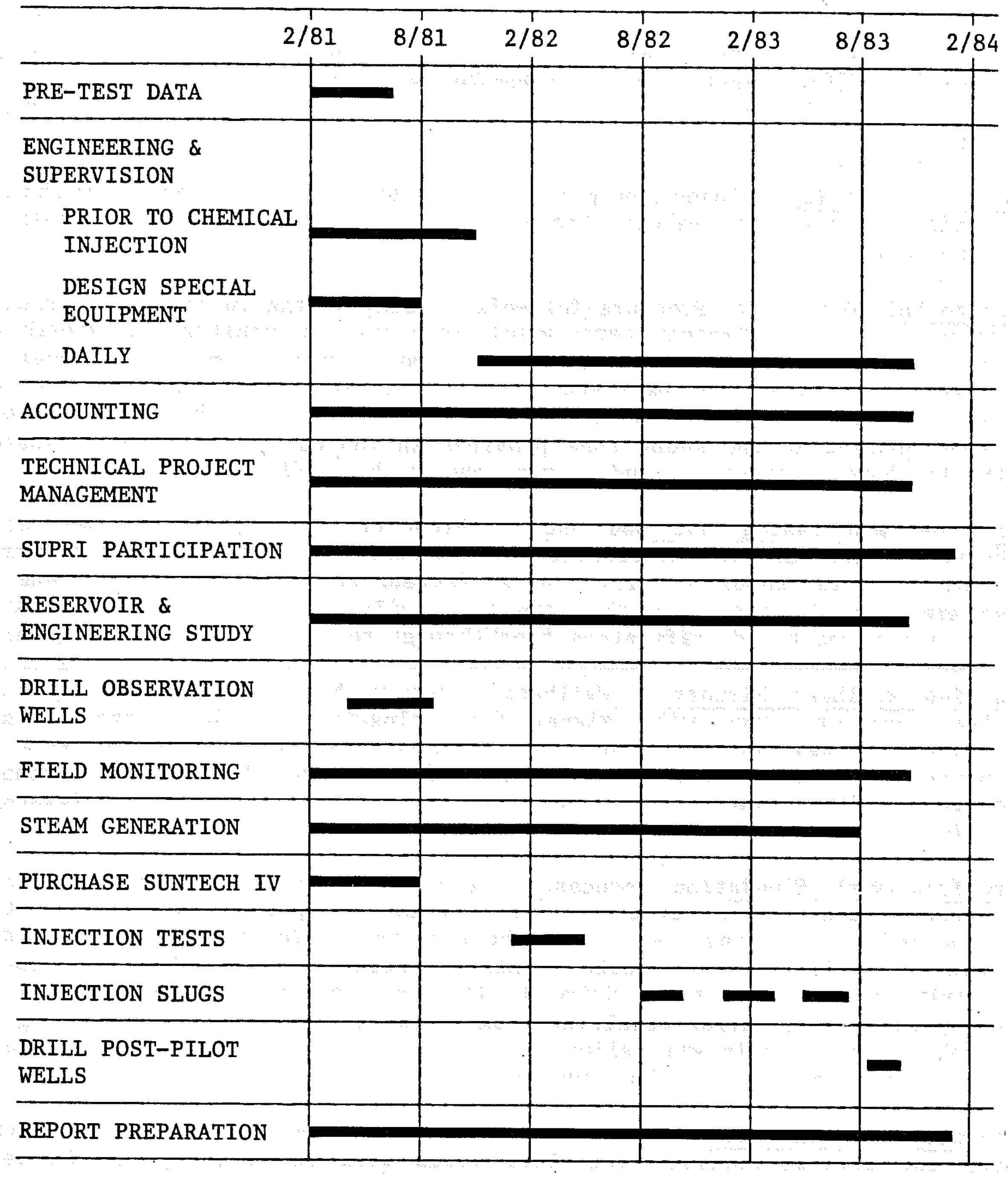


Fig. 2.1: PROJECT TIME TABLE

2.2 MONITORING PROGRAM

To evaluate the effectiveness of Suntech IV in-situ foaming to improve oil recovery by steam drive, a detailed reservoir monitoring program has been developed which includes the following monitoring tools:

Cased-Hole Logging: The observation wells will be logged at intervals of approximately three months with Carbon/Oxygen logs to observe changes in reservoir fluid saturations. Temperature logs will be run to identify steam swept zones.

Injection Profiling: Injection profiles will be obtained in Well 208 during surfactant injection to evaluate the ability of Suntech IV to divert steam in the reservoir.

Pressure Fall-Off Test: Pressure fall-off testing of the injection wells will be repeated at approximately three-month intervals to monitor the growth of the steam swept zone. Analysis of the data can be used to monitor changes in other important steamflood parameters, such as permeability-thickness (kh) of the swept zone, skin factor (s), and the heat content of the swept volume. The heat content in the swept zone provides an indication of the heat losses to the wellbore, overburden, underburden and produced fluids.

Production and Casing-Vent Gas Data: Production data will be monitored closely. An increase in oil production, reduction in water cut, and decrease in steam/oil ratio should occur if the surfactant effectively diverts steam to those areas of the reservoir that are still oil-rich. Casing-vent gas data will be monitored to identify steam breakthrough to the surrounding producers.

Injection Wellhead History: Wellhead pressure history will be observed. Wellhead pressure rise will signal foam plugging of the formation and diversion of steam into the undepleted oil-saturated intervals. In view of the unusually shallow depth (as low as 300 feet) of the injection zones, injection wellhead pressure has to be carefully monitored. A maximum wellhead pressure of 250 psia will be allowed.

Comparison with Simulation Forecast: A conventional steamflood numerical simulation model will be developed for forecasting performance of both the test and control patterns. At first, the existing production histories of the two patterns will be matched with simulation results; then, simulation forecast under conventional steam drive in the test pattern will be compared to actual production behavior resulting from steam drive with in-situ foaming in the test pattern. This will allow an estimation of incremental oil recovery by steam injection with in-situ foaming.

Post-Pilot Core Analysis: After the surfactant injection has been discontinued for several months, post-pilot wells will be drilled, one in each pattern, and cores from these two wells will be analyzed for the post-injection reservoir condition. The analysis of cores and logs obtained from the post-pilot holes will be valuable in verifying the actual extent of effectiveness of the recovery process and the accuracy of the reservoir monitoring and forecasting methods used.

3. FIELD WORK COMPLETED TO DATE

3.1 CONTRACTING AND PRELIMINARY WORK

The contract between DOE and Stanford University was signed on September 30, 1980. William E. Brigham of SUPRI is the Principal Investigator. Subir K. Sanyal, Vice-President of GeothermEx, Inc. and a Consulting Professor at Stanford University, is the Project Manager. Theodore Sumida is the SUPRI Administrator of the project. Overall project management and reservoir engineering was subcontracted by SUPRI to GeothermEX, Inc. Edward Barrera, a consultant, was subcontracted to provide assistance in the preparation and review of secondary subcontracting. The Chemical Oil Recovery Company (CORCO) was subcontracted to provide field services. CORCO also serves as an agent of the field operator, Petro-Lewis Corporation, in the project. CORCO engages various secondary field service contractors as needed.

Before any field work began, a preliminary assessment of the reservoir underlying the McManus Lease was made and an Environmental Impact Report was submitted. All available historical data from Petro-Lewis reservoir evaluation reports, well-drilling reports submitted to the Department of Oil and Gas of California (DOG), well-production data submitted to DOG, cased hole logs ("Dialog") run to locate the latest perforations, and all existing well logs were gathered and examined. A set of detailed geologic sections was prepared based on correlation of well logs. The effects of the project on physical, socio-economic and human environments were evaluated. Investigations revealed that the field experiment would actually prove to be beneficial to the overall environment because improved oil recovery through the use of ancillary materials would result in less fuel being burned in the steam generators, thus reducing sulfur dioxide, nitric oxide and particulate emmissions to the air.

Based on the preliminary geologic model developed, two inverted five-spots on 2.25 acre spacing were selected for the field experiment. Sites for the observation wells were also selected. The five-spot centered on injection Well No. 208 (Fig. 1.2) was chosen to be treated with Suntech IV surfactant (the "Test Pattern"). The five-spot centered on injection Well No. 214 (Fig. 1.2) was selected as the "Control Pattern," which is to undergo conventional steam drive without surfactant.

These two five-spots were selected from among the others within the McManus Lease because they were the only two among the available five-spots that were "fully developed," i. e., surrounded by other five-spots on all sides. Of these two, the five-spot centered on Well 208 was chosen as the test pattern because it had been undergoing steam injection since the summer of 1978, while the injector (Well 214) in the control pattern was yet to be drilled when the pilot started. In addition, from the available well data, these two five-spots could be better defined geologically than the others.

The observation well sites were chosen to be due northeast of the respective injectors because the preliminary geologic model showed a structural dip towards the southwest, indicating a better sweep will exist to the northeast of the injector compared to other directions. The observation wells were drilled midway between the injector and the northeast producer in each pattern.

3.2 DRILLING, CORING, LOGGING AND COMPLETION

The two observation wells (208M and 214M) as well as the "control" injector, Well 214, were drilled in August 1981. The hole diameter for these wells is 7 5/8 inches. By comparison, the hole diameter of the "test" injector, Well 208, is 9 5/8 inches. Wells 208M and 214M, which were drilled to total depths of 485 and 445 feet, respectively, were cased to total depth. The casings were cemented to the surface through a float valve and basket assembly but were not perforated. Well 214 was drilled and cased to 406 feet.

Cores were obtained using both rock and drag bits during drilling. Core recovery, however, was poor because of the presence of large boulders. Due to the unconsolidated nature of the formation, both whole cores and sidewall cores were heavily damaged during the extraction process and in some intervals were completely lost. Some of the fines (silt and clay) from the cores were washed out during core handling. Frozen cores were shipped to Core Laboratories for analysis. Samples of drill cuttings were collected and sidewall cores were taken to supplement core data. Five-inch wellheads were installed along with guards around the wellheads for protection.

Extensive suites of both open-hole and cased-hole logs were run in both observation wells (Table 3.1 and Figs. 3.1 and 3.2). Open-hole logs run in both wells in August 1981 included Schlumberger's FDC-CNL Gamma Ray log, Nuclear Magnetic log, Electromagnetic Propagation Tool and Duel Induction-SFL log. In addition, Schlumberger provided Cyberlook field interpretation. Each observation well was also logged with Dresser-Atlas' Spectralog and Gearhart Industries' Dielectric Constant log, both in open-hole. Early in September 1981, following the casing of the wells, Schlumberger ran their Dual Spacing Thermal Neutron Decay Time and Cement Bond logs in the two observation wells and their newest product, the Gamma Ray Spectroscopy log, in 214M only. Dresser Atlas also ran their Carbon/Oxygen log in both observation wells in August 1981, as well as in February and May 1982. Lastly, the U.S. Geological Survey (USGS) ran temperature logs in both 208M and 214M in November 1981. Preliminary interpretation of the log suites from the two wells were made from the analog prints supplied by each company. A more complete analysis of the digitized log data output is being conducted. After analysis is completed, recommendations will be made as to which combination of logs is most useful and cost effective for such a steam flood project.

Schlumberger VOLAN (open-hole) and Production Management (cased-hole) computer-processed logs were also supplied in August 1981 and January 1982, respectively.

Table 3.1

LIST OF LOGS RUN IN OBSERVATION WELLS

OPEN-HOLE LOGS	COMPANY	DATE
FDC-CNL Gamma Ray	Schlumberger	8/81
Nuclear Magnetic Log	Schlumberger	8/81
Electromagnetic Propagation Tool	Schlumberger	8/81
Duel Induction-SFL	Schlumberger	8/81
Cyberlook	Schlumberger	8/81
Spectralog	Dresser-Atlas	8/81
Dielectric Constant	Gearhart Industries	8/81
CASED-HOLE LOGS	**COMPANY**	**DATE**
Dual Spacing Thermal Neutron Decay Time	Schlumberger	8/81
Cement Bond	Schlumberger	8/81
Gamma Ray Spectroscopy (in Well 214M only)	Schlumberger	8/81
Carbon/Oxygen	Dresser-Atlas	8/81 2/82 5/82
Temperature	USGS	11/81
COMPUTER-PROCESSED LOGS	**COMPANY**	**DATE**
VOLAN	Schlumberger	8/81
Production Management	Schlumberger	1/82

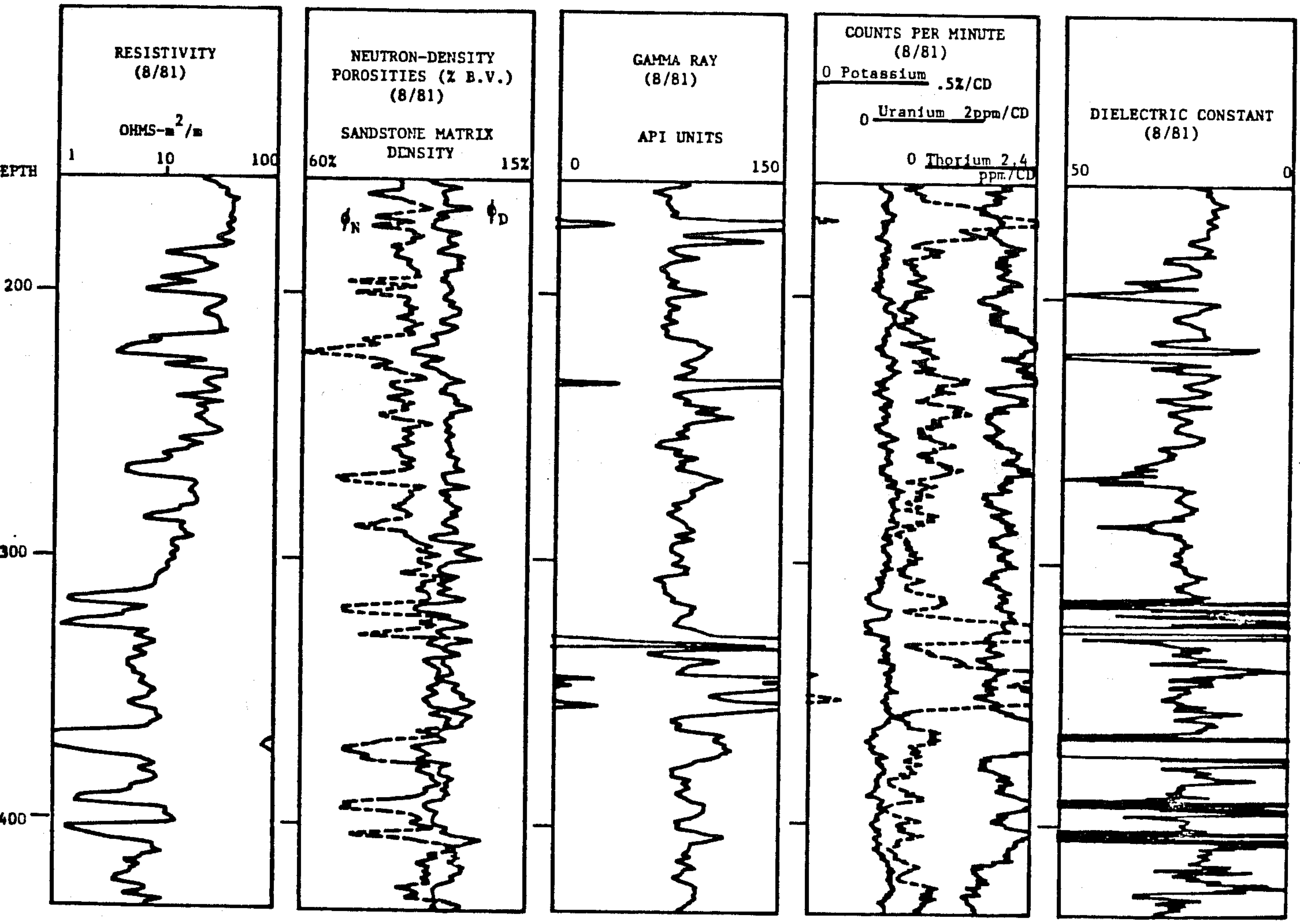
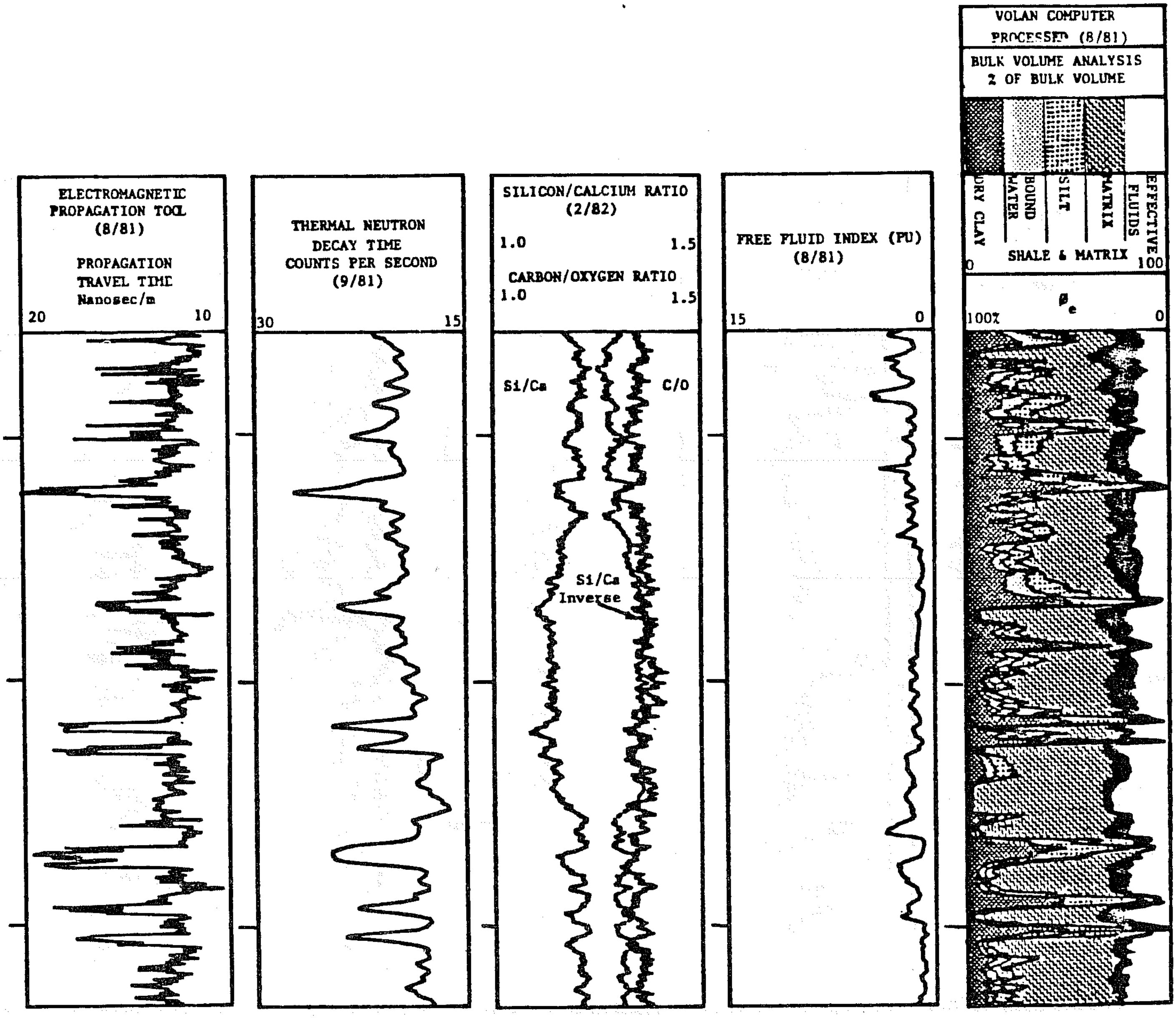


Fig. 3.1: WELL LOG SUITE FOR WELL 208M


ELECTROMAGNETIC PROPAGATION TOOL (8/81)
PROPAGATION TRAVEL TIME Nanosec/m
20 10
THERMAL NEUTRON DECAY TIME COUNTS PER SECOND (9/81)
30 15
SILICON/CALCIUM RATIO (2/82)
1.0 1.5
CARBON/OXYGEN RATIO
1.0 1.5
Si/Ca
C/O
Si/Ca Inverse
FREE FLUID INDEX (PU) (8/81)
15 0
VOLAN COMPUTER PROCESSED (8/81)
BULK VOLUME ANALYSIS % OF BULK VOLUME
DRY CLAY
BOUND WATER
SILT
MATRIX
EFFECTIVE FLUIDS
0 SHALE & MATRIX 100
100% ϕ_e 0

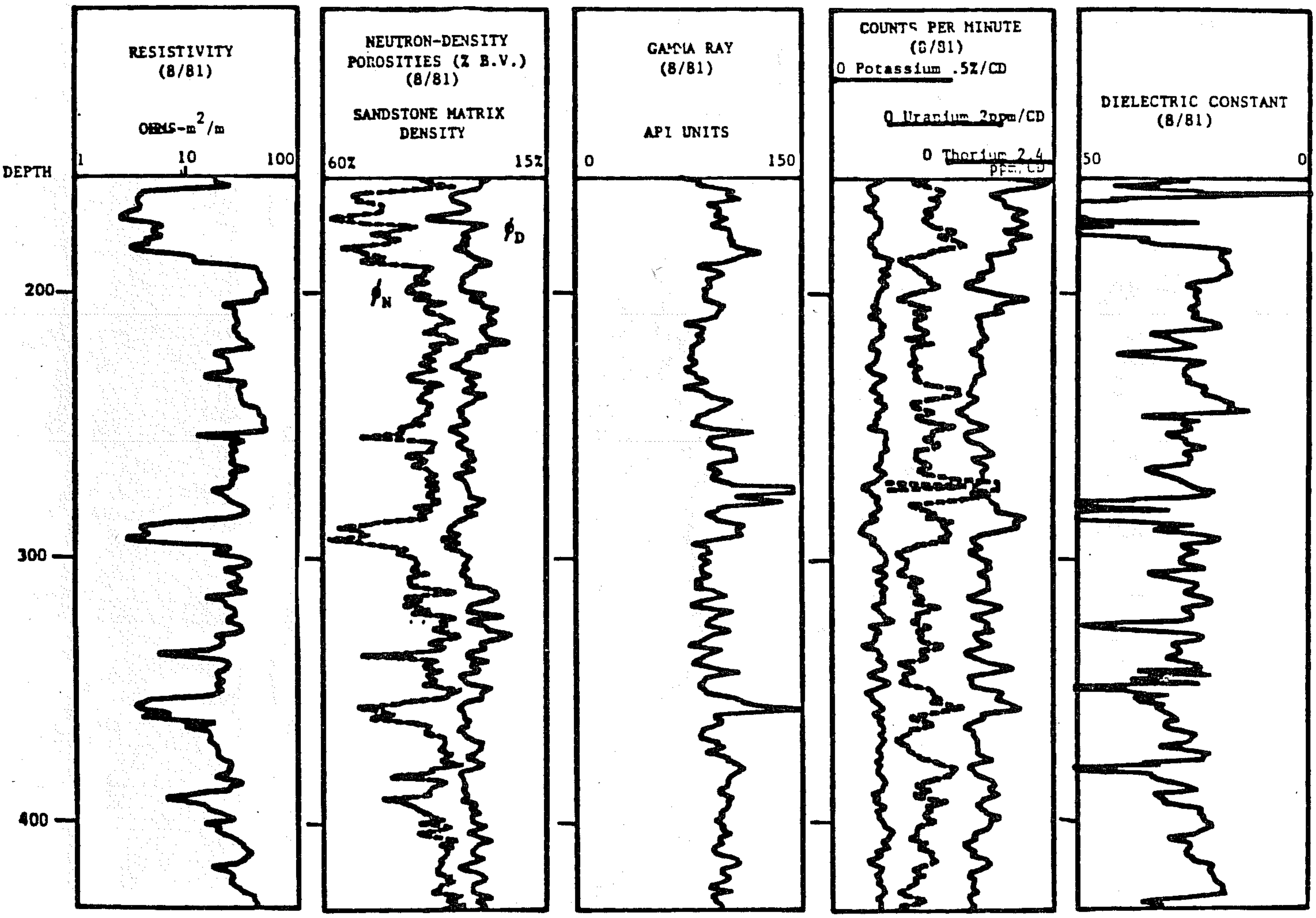
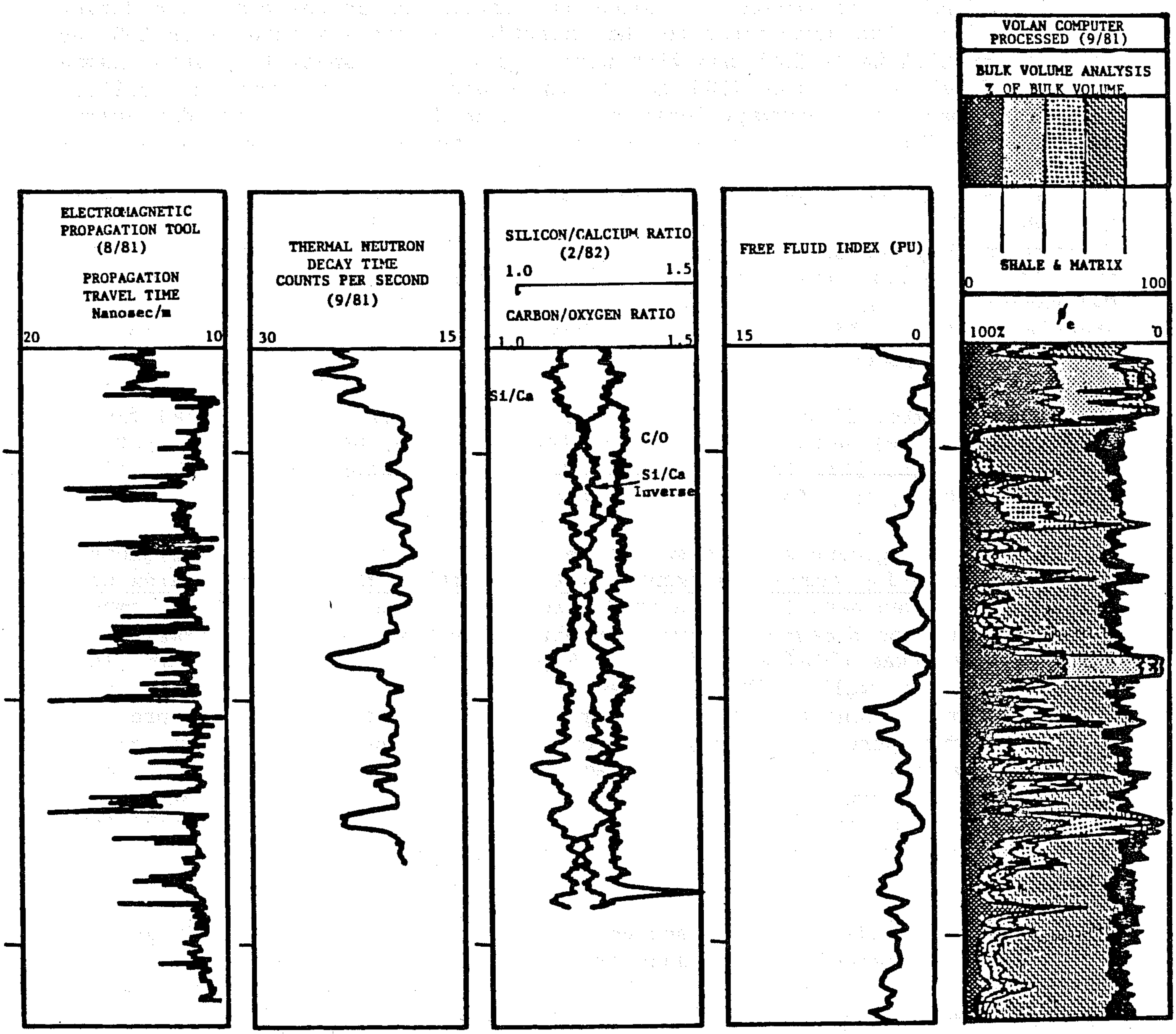


Fig. 3.2: WELL LOG SUITE FOR WELL 214M


ELECTROMAGNETIC PROPAGATION TOOL (8/81)
PROPAGATION TRAVEL TIME Nanosec/m
20
10
THERMAL NEUTRON DECAY TIME COUNTS PER SECOND (9/81)
30
15
SILICON/CALCIUM RATIO (2/82)
1.0
1.5
CARBON/OXYGEN RATIO
1.0
1.5
Si/Ca
C/O
Si/Ca Inverse
FREE FLUID INDEX (PU)
15
0
VOLAN COMPUTER PROCESSED (9/81)
BULK VOLUME ANALYSIS
% OF BULK VOLUME
SHALE & MATRIX
0
100
100%
0

3.3 WELL-TO-WELL TRACER TESTING

To help define the reservoir, a radioactive tracer survey was conducted during November 1981. Two days prior to the injection of tracers into Wells 208 and 214, observation Wells 208M and 214M were logged with a special spectral gamma ray log developed by the USGS to obtain a background radioactive profile. During the background survey, however, 18 and 69 feet of fill were discovered in 208M and 214M, respectively. Workover of the wells to remove the fill delayed tracer injection until November 19. On November 19, 1981, Tritium, Krypton-85, Sulphur Hexafluoride (SF_6) and Freon-14 were injected into Well 208, while Tritium and Krypton-85 were injected into Well 214. Because both Tritium and Krypton-85 are radioactive isotopes, the quantity of each injected into the formation was limited to the maximum allowable by the State of California. During the injection of Krypton-85 in both wells, USGS surveyed observation Wells 208M and 214M with their spectral gamma ray log to monitor the flow of Krypton-85.

Beginning November 20 and continuing until December 1, 1981, produced fluids and vapor samples were gathered from the producing wells in each pattern (Wells 113B, 114, 119, 120, 125, 126, 132 and 133). Samples were shipped to Teledyne Isotope, Inc. for analysis of the concentrations of tracers present.

In May 1982, background samples were taken to establish a baseline for another tracer survey using common inorganic salts. Samples of produced fluids were obtained for seven days from each production well to be tested. These samples were evaluated for background levels of nitrate and bromide ions. A sample of formation sand was obtained from each injection pattern following the clean out of production wells. The sand was cleaned and dried. A part of the sand was poured into a container full of 10 ppm sodium nitrate solution in produced water. Another part of the sand was poured into a container of 10 ppm sodium nitrate solution. The samples were agitated for five minutes, twice a day, five days a week for four weeks. The solutions in the containers were then analyzed for nitrate and bromide ions. These tests indicated negligible levels of adsorption of the ions on formation sand. Therefore, tracer adsorption on sand was ignored in the analysis tracer response.

On June 2, 1982, 1000 pounds of sodium bromide (NaBr) dissolved in 550 gallons of water were injected into McManus Well 208 at 11 gallons per minute (gpm). On the same day, 1000 pounds of sodium nitrate ($NaNO_3$), also dissolved in 550 gallons of water, were pumped into McManus Well 214 over a 50 minute period. Sampling of fluids from the producing wells in each pattern began 2 hours after injection started. Samples were taken every 2 hours for the first 3 days, every 4 hours for the next 9 days, and every 12 hours for the last 10 days. Another similar tracer injection was conducted in June 1982 after the conclusion of the first slug injection.

3.4 INJECTIVITY TESTING

Before introduction of large slugs of Suntech IV in the reservoir, it was planned to inject a small amount of Suntech IV to check if injection wellhead pressure would increase, indicating foaming in the formation, and if the injection profile could be altered, indicating diversion of steam due to foam. Such an "Injectivity Test" would also reveal any potential operational problems in storing, handling or injecting Suntech IV. Operational procedure for the injection of the main surfactant slugs would be based on the experience gained from the injectivity test. Figure 3.3 shows the completion in injector Well 208.

The injectivity test was conducted in December 1981. To obtain an injectivity profile, a radioactive background is first obtained across the interval of investigation (in this case, 300 to 450 feet). The gamma ray tool (GR) is then stationed above the perforations and five mC of I-131 in a carrier solution of salt and water is released into the wellbore during steam injection. Tracer entering the formation temporarily increases the radioactivity of the formation. The time it takes for the radioactive slug to pass the tool is monitored and recorded. When the radioactive slug completely passes the GR detector and the background level of radiation is seen, the logging runs are begun. Three runs are made and compared to ensure that they correlate to one another, i.e., the same peaks occur at the same depths. Differences in peak intensity are acceptable.

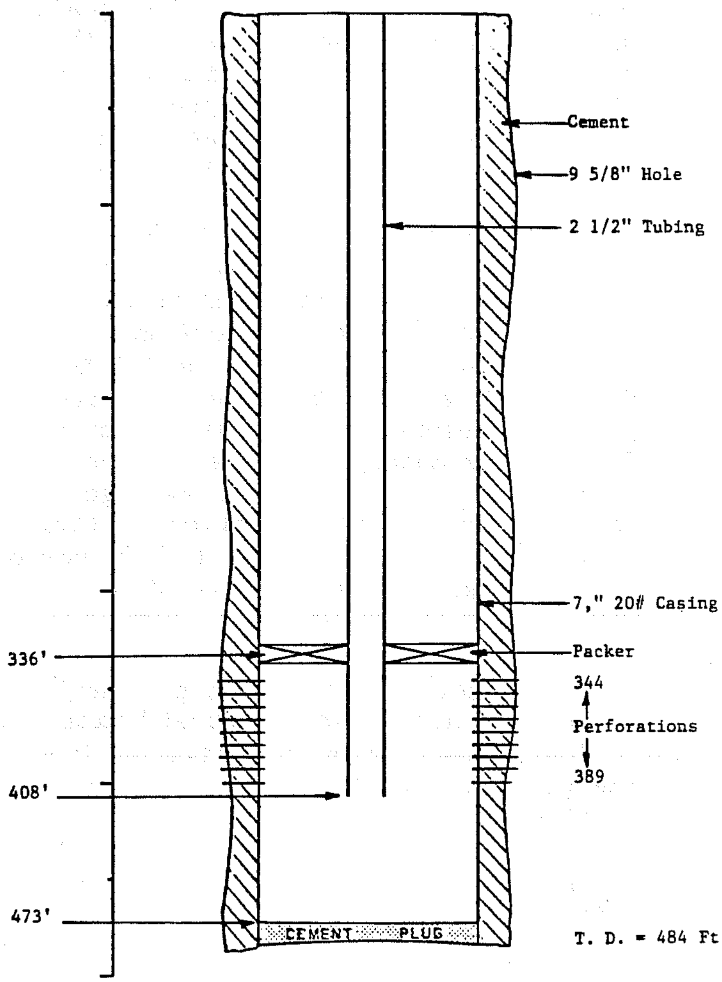


Fig. 3.3: SCHEMATIC OF INJECTION-HOLE WELL COMPLETION--WELL 208

The last logging run is used to obtain the injectivity profile. The log is broken into five-foot intervals and the area of the GR curve, less the background level, is compared to the entire area to yield the percentage of gas entering the formation at a specific depth. The process is then repeated using water-soluble I-131. Thus, separate injectivity profiles are developed for both steam and water.

On December 2, 1981, 2300 gallons of 15% active Suntech IV were delivered to the well site. The chemical was inspected, but appeared to have different physical characteristics (a brown opaque emulsion) than the material tested earlier in the year at SUPRI. Quality control testing at CORCO to determine activity level, pH and foaming ability, showed that the surfactant batch was only partially in solution and would not generate foam. To promote miscibility with water, isopropyl alcohol (11% concentration by weight) was added to the surfactant. It should be noted that alcohol addition had not been necessary with the materials tested earlier. The pH of the surfactant also varied over different portions of the batch.

Over a 63-hour period, 0.5 gallons per minute (gpm) Suntech IV solution was continuously injected with ±80% quality steam into the reservoir to produce a 4% (by weight) concentration at the sandface. After 46 hours of injection, only a minimal pressure rise was observed at the injection wellhead. During the injectivity test, injectivity profile surveys were run frequently to monitor any change. Unexpected operational problems caused by faulty surfactant made the first injectivity test inconclusive.

A second injectivity test in McManus 208 was performed in March 1982. During this test, a total of 2500 gallons of 15% active Suntech IV was injected in two stages. Beginning on March 10, 1982, 1380 gallons of surfactant were injected continuously at 0.7 gpm over a 33 hour period. Again, chemical and steam (±80% quality) were added to produce a 4% by weight concentration of Suntech IV at the sandface. A significant pressure rise from 75 psig to 130 psig was observed at the injection wellhead. Treatment was then discontinued for approximately 5 days. When surfactant treatment was resumed, the surfactant injection rate averaged 0.8 gpm. Approximately 13 hours after resuming surfactant injection, nitrogen was introduced into the flowstream at a rate of 100 SCFM over a 6 hour period. A 70 psi pressure rise to 150 psig was observed at the wellhead when the combination of nitrogen, surfactant and steam was injected into the reservoir.

Injection profiles for both gas- and water-phase tracers were obtained before, during and after surfactant addition. Injectivity profiles were also obtained following completion of nitrogen injection. Samples of produced fluids from the producing wells in the test pattern were gathered and tested for emulsion problems.

Injectivity tests were also conducted during the first slug injection in July 1982. Details of slug injection are discussed under Section 3.7.

3.5 PRESSURE FALL-OFF TESTING

To monitor the growth of the steam swept zone, injection well pressure fall-off surveys were performed on steam injection Wells 208 and 214 in October 1981, February 1982 and May 1982. Well 208 has undergone continuous steam injection since July 1978, while Well 214 has been on steam injection only since mid-October 1981.

The testing equipment used during the pressure fall-off tests consisted of a capillary tube filled with helium, a helium purge system, a downhole pressure chamber, a quartz-crystal pressure transducer (rated at 900 psi), and an analog recorder. Figure 3.4 is a schematic of the well setup used for pressure fall-off testing.

Before shut-in, a capillary tube was lowered into the well and set at the mid-perforation point. The capillary tube was then flushed with helium from the purge system. An open-ended pressure chamber is attached at the lower end of the capillary tube. After the readings had stabilized, the well was shut-in and fall-off pressure was recorded as a function of time. Calculation of the weight of helium in the capillary tube was not necessary because the change in density of the helium column with pressure is negligible. Therefore, the pressure change records are accurate without any correction. This setup provides pressure change readings accurate to +0.01 psi under ideal conditions.

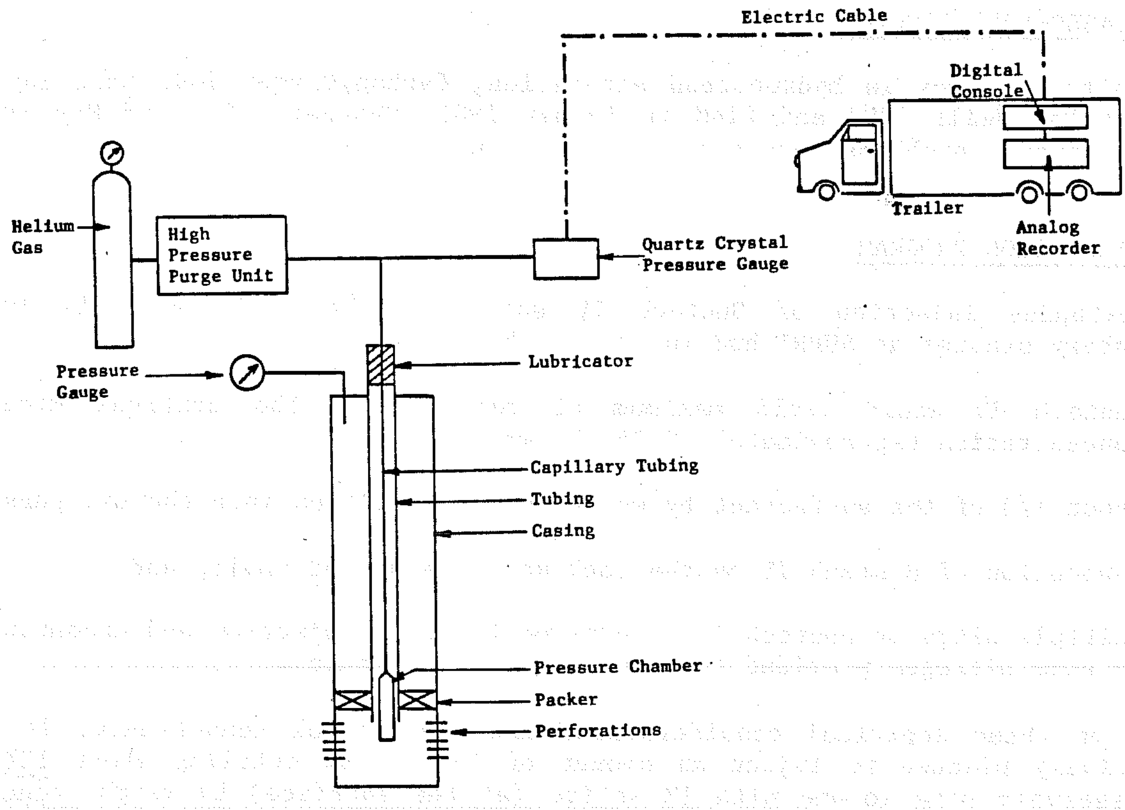


Fig. 3.4: SCHEMATIC OF PRESSURE FALL-OFF TEST SETUP

Typically, initial pressure readings were recorded every 30 seconds for the first 0.5 to 1.0 hour of the test. Then, pressure readings were taken every minute for 0.25 to 0.5 hour, followed by readings every 5 minutes for 1.0 to 1.5 hours. For the remainder of the test, which lasted 15 to 21 hours, pressure readings were recorded every 15 minutes.

Some difficulties were encountered during the pressure fall-off testing. When Well 208 was tested on November 1, 1981, the pressure began to increase after 180 minutes of shut-in time. The unexpected increase was caused by a rising liquid level in the wellbore and submersion of the capillary tube below the water level. This happened because the capillary tube was wrongly set below the perforations. The February 10, 1982 test for Well 208 also showed an upward deviation from the established pseudo-steady state pressure decline at approximately $\Delta t = 1.1$ hours. The deviation lasted until $\Delta t = 10$ hours. The reason for this sudden pressure rise is not clear. Steam condensation, phase segregation, some unknown phenomena characteristic of Well 208 itself, or interference from surrounding injectors could possibly be responsible.

During the third pressure fall-off test in Well 208 on May 18, 1982, a pressure rise was again seen after approximately 100 minutes of shut-in time. Examination of the testing and well equipment, however, showed no changes or malfunctions.

3.6 CASED-HOLE LOGGING

To monitor changes in hydrocarbon saturation, Carbon/Oxygen logs were run in observation Wells 208M and 214M in August 1981, February 1982 and May 1982. No operational problems were encountered during this logging.

3.7 INJECTION PROGRAM

The extended injection of Suntech IV surfactant began in mid-July 1982. Laboratory studies at SUPRI had indicated that:

1) Suntech IV would yield maximum oi recovery at the critical micelle concentration (approximately 0.25% by weight);

2) About 1/3 of the surfactant by weight would partition into the oil phase;

3) Adsorption of Suntech IV on the rock matrix appeared small; and

4) Multiple slugs of Suntech IV alternated by steam injection and accompanied by some nitrogen provided the best recovery mechanism.

Based on these empirical considerations and operational convenience, it was tentatively planned to inject an amount of Suntech IV totaling about 10% of the reservoir pore volume with 1% active (at the sandface) by weight concentration. According to these estimates, approximately 100,000 pounds of surfactant will be required. Each slug will consist of about 20,000 pounds of surfactant. A 15% active by weight solution (at the surface) will be injected at a suitable rate which will be determined from the first slug injection effort. Initially, a rate of 0.5 gallons per minute (gpm) was planned. At this design rate, about three weeks will be required to inject one slug. Each 20,000 pounds of 15% active slug will have a volume of approximately 16,000 gallons.

Suntech IV, the surfactant used, was manufactured by Suntech Corporation in Richardson, Texas and neutralized by Pacific Soap in San Diego, California. It was stored by Chemex in Bakersfield, California until needed at the field surfactant injection system. At the field site, the surfactant solution was stored in three 3000-gallon polypropylene tanks. Shipments from storage in Bakersfield were received at the field in increments of 6000 gallons.

Before entering the pumping system, the surfactant was filtered to remove any debris or solid chunks of surfactant which may have formed during storage due to surface liquid evaporation. The surfactant was pumped from the storage tanks to a high-pressure piston pump by using a small gear pump (Fig. 3.5). The gear pump was used because the piston pump did not develop sufficient suction to move the viscous surfactant solution. From the feed pump, surfactant flowed through a second in-line filter, a flow meter, and a valving arrangement to the wellhead where the surfactant was injected simultaneously with steam and/or nitrogen.

Injection of the first 20,000 pound slug of Suntech IV began on July 14, 1982 at 7:35 a.m. at a rate of 0.25 gpm. At this injection rate, wellhead pressure averaged 80 psi. Because the injection rate was less than the design rate of

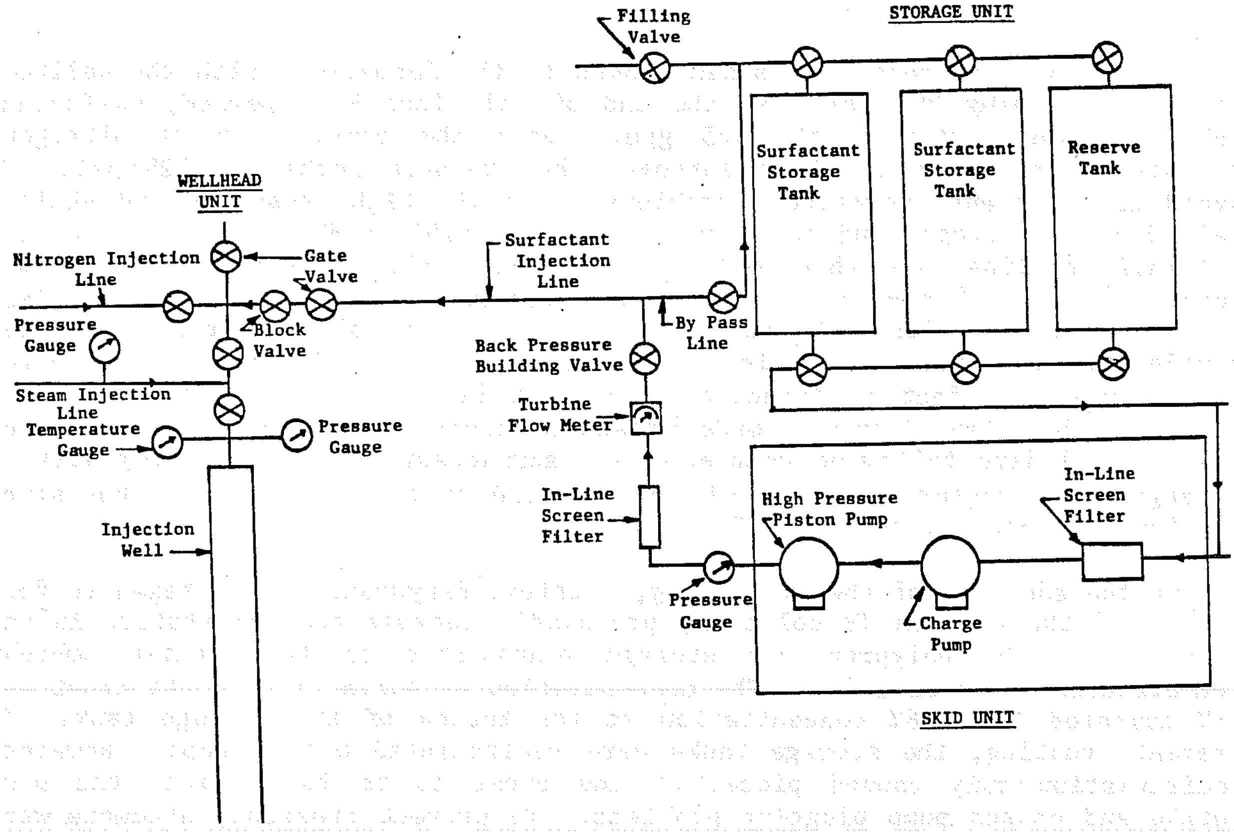


Fig. 3.5: SCHEMATIC OF INJECTION SETUP

0.5 gpm and the wellhead pressure did not increase (a sign of foam plugging of the formation), Suntech IV injection was increased first to 0.75 gpm, then to 1.1 gpm and finally to 1.25 gpm. At 1.25 gpm, pressure stabilized at 125 psi indicating surfactant concentration in the reservoir was sufficiently high to produce effective foaming.

On July 19, nitrogen was introduced into the flowstream following 26 hours of Suntech IV injection at 1.25 gpm. A total of 100,000 SCF flowed into the reservoir over an 8 hour period while a constant 25 psi pressure difference was maintained between the nitrogen tank and wellhead. The combination of nitrogen, surfactant and steam caused the pressure to peak at 210 psi. When nitrogen addition was discontinued, pressure dropped immediately and eventually stabilized at 150 psi.

After nitrogen addition was terminated, the surfactant injection rate was varied from 0.9 to 2.0 gpm and the wellhead pressure response was observed. Generally, increasing surfactant flowrate increased wellhead pressure, while decreasing surfactant flow decreased wellhead pressure.

After 86 hours of continuous surfactant injection at 1.5 gpm, a second slug of nitrogen (200,000 SCF) was injected into the reservoir. Nitrogen injection at 12,800 SCF began on July 28 at 7:20 a.m. During the first four hours of injection, only nitrogen and steam flowed to the formation, with the wellhead pressure reaching 200 psi. At the end of this four hour period, surfactant injection was restarted at 1.25 gpm. With the combination of nitrogen, surfactant and steam in the reservoir, the pressure peaked at 225 psi. To avoid creating any operational problems given the high pressures and shallow well depths, nitrogen injection was reduced to 8,500 SCFH. Wellhead pressure initially declined and then peaked at 235 psi. When nitrogen injection was terminated at 5:50 p.m. on July 28, the pressure declined but then stabilized at 140 psi. On July 29, injection of the first slug of surfactant was completed. The pressure continued to be monitored and within 2.5 hours after discontinuing surfactant injection, pressure dropped to 125 psi. Frequent generator downtime, however, made pressure response monitoring difficult for the first 3 days following completion of surfactant injection. From July 31 to August 2, pressure declined slowly from 120 to 100 psi, where it has since remained (through August 6, 1982).

During the addition of the first slug, a thick, dehydrated crust began to form on top of the Suntech IV solution, presumably because the temperature in the interior of the polypropylene storage tanks rose to 140°F while ambient temperatures measured 107°F. The concentration of surfactant in the crust was 26% compared to a 16% concentration at the bottom of the storage tank. To prevent crusting, the storage tanks were recirculated with a pump. However, recirculation only caused pieces of the crust to be forced into the pump intake and caused pump plugging problems. To prevent crusting, attempts were made to generate a foam blanket by spraying surfactant into the storage tanks at 200 gpm. The high flow rate created a thick insulating blanket. Although the blanket eventually dissipated, crusting due to surface liquid evaporation was prevented.

3.8 PRODUCTION TESTING

Production data for oil, water and steam are being monitored. Problems have been encountered in accurate metering of the production and injection rates. Production rates measured by the inline meters do not always agree with the quantity of oil in the stock tank. The discrepancy exists because: three different inline meters have been used to measure oil production; all the wells on the lease do not flow through the same meter; and the meters have not been calibrated in the past. In addition, the meters probably are not large enough to provide the residence time needed for separation of the gas (steam) and oil phases where steam breakthrough has occurred. If the vapor is not separated, the meters see the gas as liquid and over-estimate the amount of oil produced. In addition, steam quality at the wellhead and steam injection rate are not well controlled.

We are currently attempting to reconcile these differences. CORCO has rented a standard unit used for heavy oil testing and has calibrated this meter by flowing oil through the meter, weighing the collected fluid, and measuring the fluid density. We believe that the three meters currently being used to measure oil production from the McManus Lease should be calibrated with the rental unit. By installing the calibrated meter in series after the Petro-Lewis (PL) meters, the PL meters can be adjusted so that mesured flow matches with that of the calibrated rental. CORCO has also designed and had fabricated a portable tank for collecting the flow from the series meter installation. Collected fluids can be used to calibrate both the rental and PL meters. Once the PL meters have been calibrated, a correction factor will be applied to the existing production data so that historical production trends can be established. (NOTE: After this report was written, the testing mentioned above was performed and the production measurement problems now appear to be solved.)

4. DATA ANALYSIS

4.1 GEOLOGICAL CORRELATION

A set of detailed geologic sections based on correlations of resistivity logs was prepared. Usually the resistivity log is not a good tool for well-to-well correlation. The SP or Gamma Ray (GR) log normally is used for well log correlation. IN the Kern River field, however, several problems prevent the use of these conventional logs. The SP log is not well developed because of the lack of resistivity contrast present between the formation water and the drilling fluid. The GR log proved to be of little value in correlation because steam channels caused spikes in certain places and most of the existing wells did not have gamma ray logs. The porosity logs could not be used for correlation because they were not available in all wells. Where porosity logs were available, the distinctions between silt, sand and shale were not easily made because the Kern River field formation is essentially a silty sand with the fraction of clay versus sand-size particles dictating permeability. Lastly, because few readily identifiable marker horizons exist, correlation was also difficult. A resistivity of 10 ohm-m was arbitrarily selected as the cutoff to distinguish between impermeable (silt/shale) and permeable (sand) slices. The match with horizontal markers known to exist at specific wells (from cores) was not perfect. A portion of a typical correlated section is shown in Fig. 4.1.

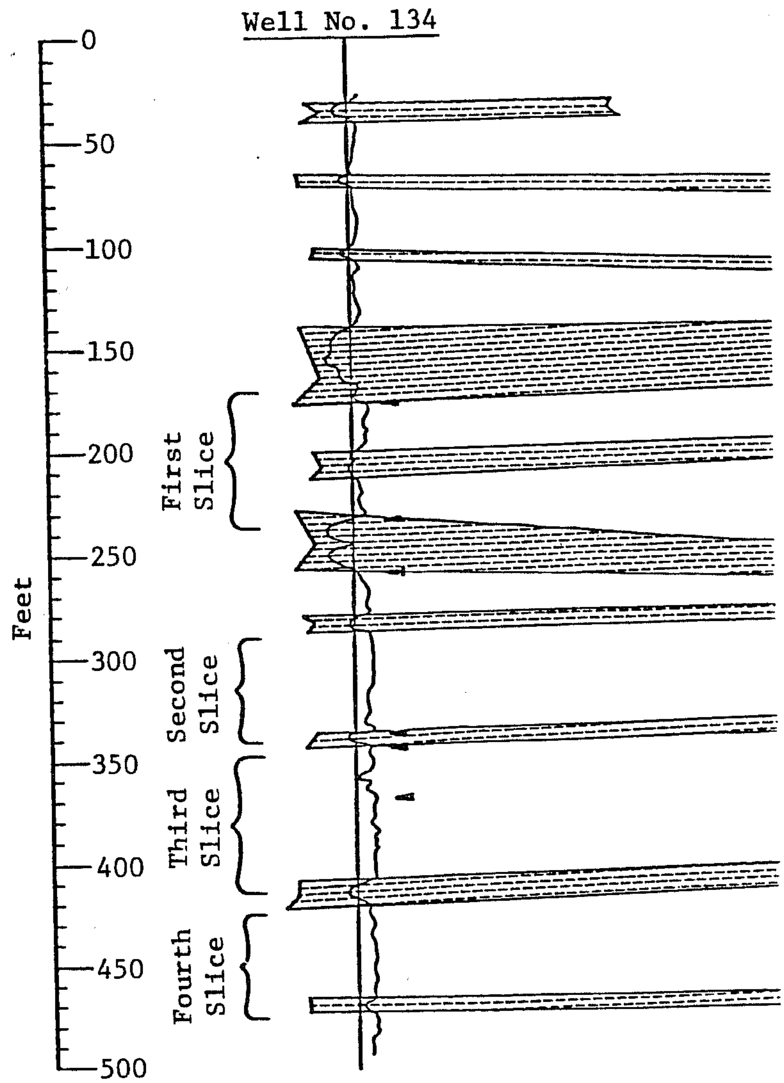


Fig. 4.1: GEOLOGICAL CORRELATION

4.2 QUALITATIVE ANALYSIS OF CORE AND LOG DATA

To decipher the details of the layering, including which slices are taking steam and how much desaturation has occurred in various slices, the core and log data were analyzed qualitatively. First, geologic sections between the injection well and each of the four surrounding producing wells in both the test and control patterns were prepared by correlating shales on gamma ray logs (Wells 208 and 208M) and conductivity logs (Wells 208, 208M and producers). Figures 4.2 through 4.5 show the correlations between Well 208, the injection well in the test patterns and each of the surrounding producers (Wells 113B, 114, 119 and 120). Figures 4.6 through 4.9 show the correlations between Well 214, the injector in the control pattern and each of the surrounding producers (Wells 125, 1126, 132 and 133).

In the test pattern (Well 208), four major slices (1, 2, 3 and 4) can be readily identified. The locations of the tops and bottoms of each slice are in reasonable agreement with those previously established in a study of the same lease by Todd, Dietrich and Chase, Inc. [1980]. In the present study, slices 2 and 3 were further subdivided into slices 2A, 2B, 3A and 3B based on the presence of recognizable impermeable shale/siltstone beds within the test pattern. By comparison, the control pattern (Well 214) contains fewer sand and shale slices. Only three slices can be identified: 1, 2A and 3A.

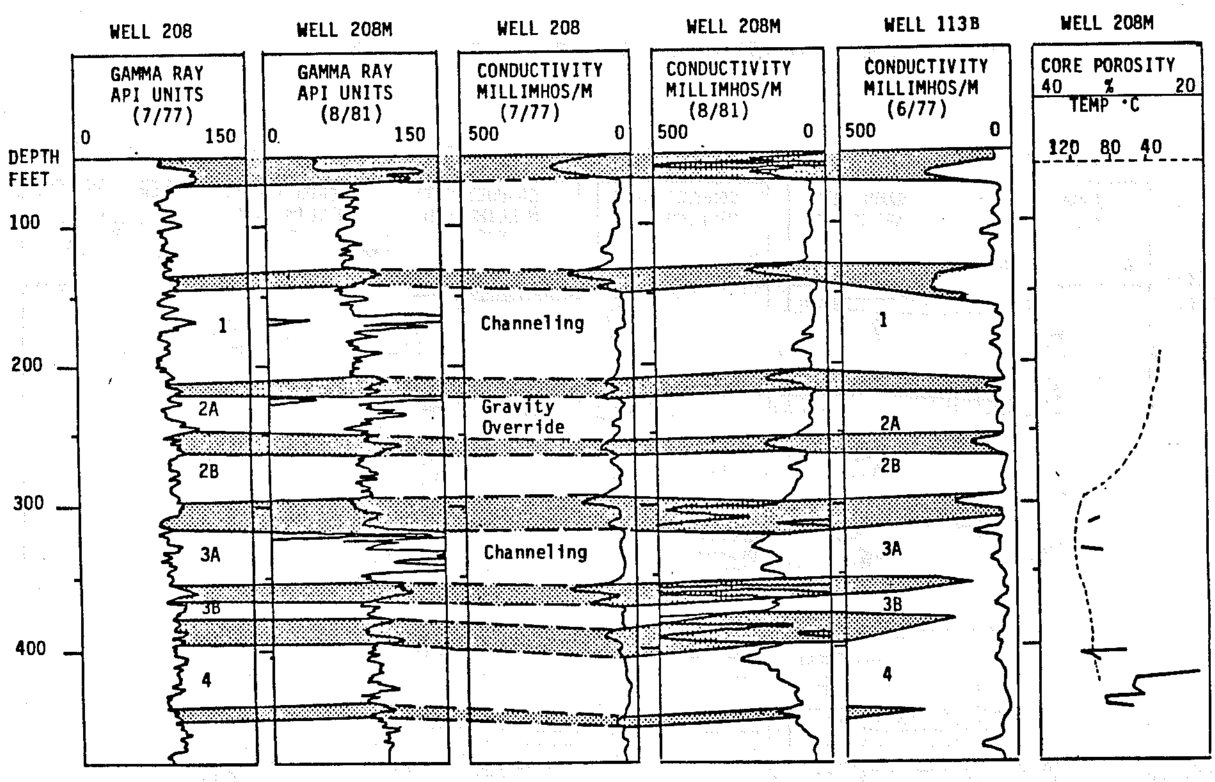


Fig. 4.2: CORRELATION BETWEEN WELLS 208 AND 113B

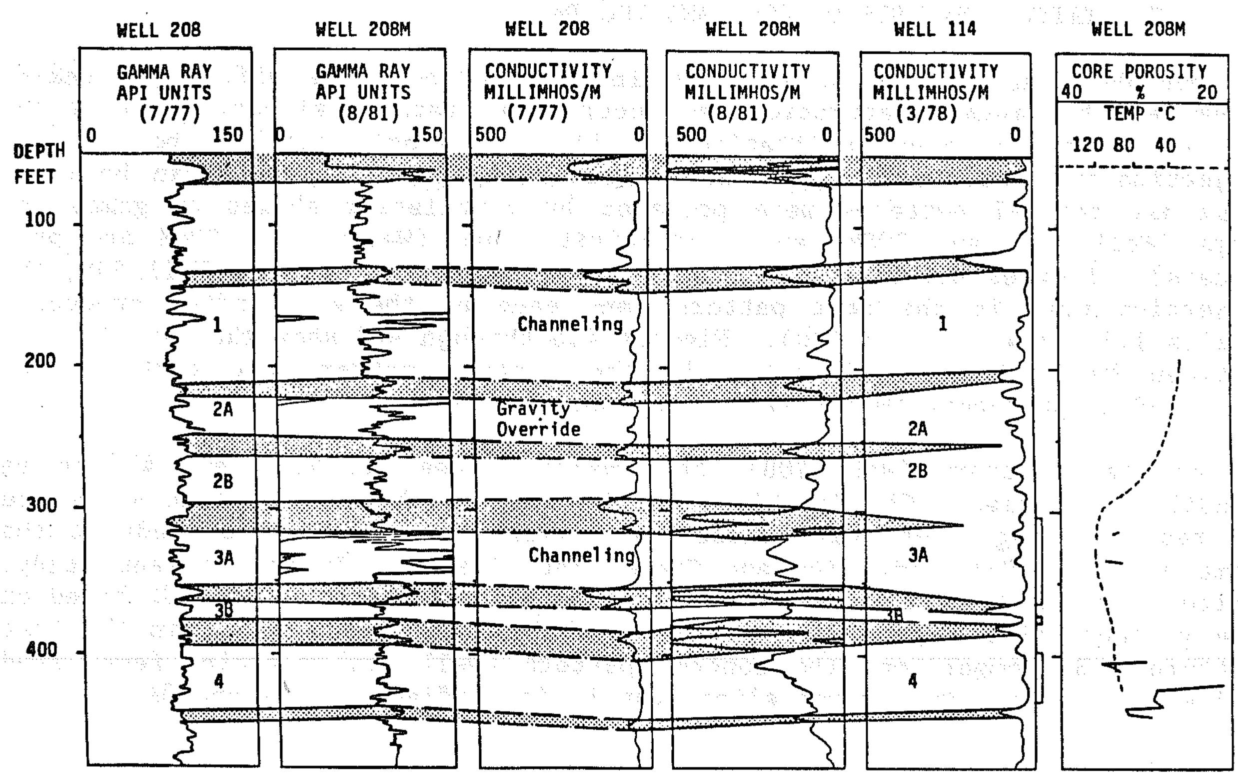


Fig. 4.3: CORRELATION BETWEEN WELLS 208 AND 114

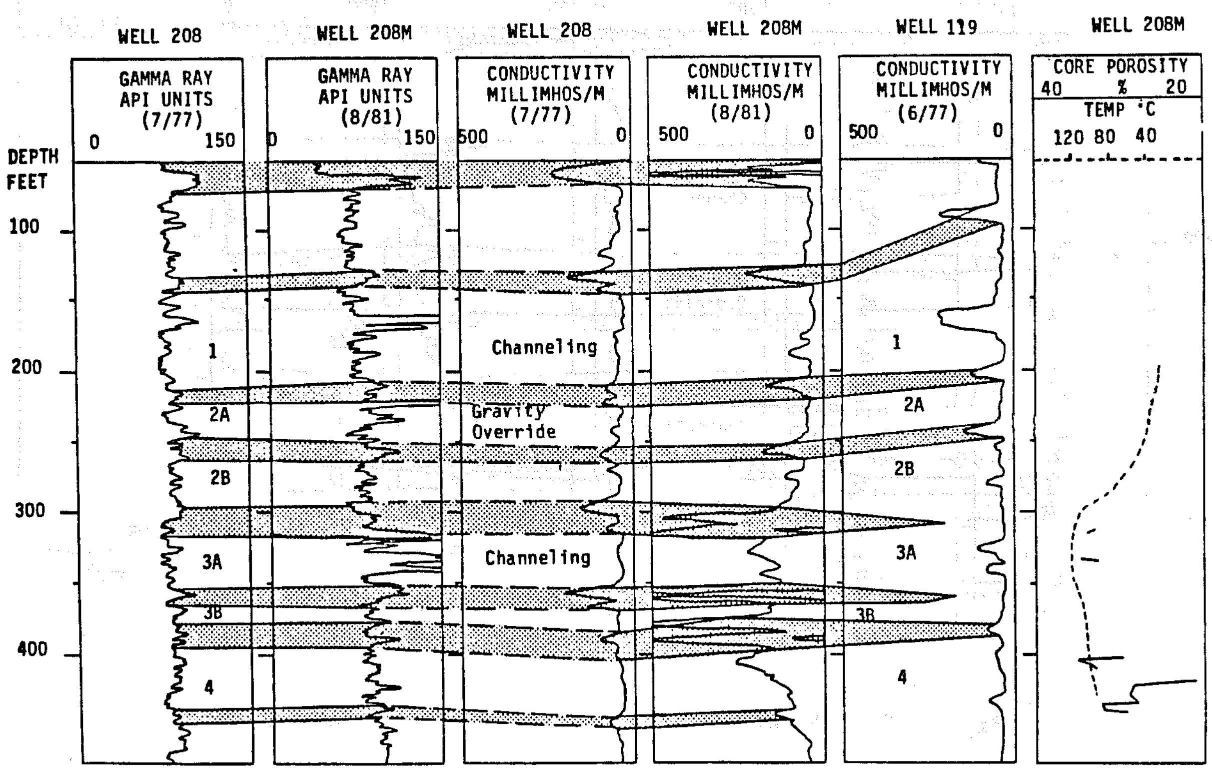


Fig. 4.4: CORRELATION BETWEEN WELLS 208 AND 119

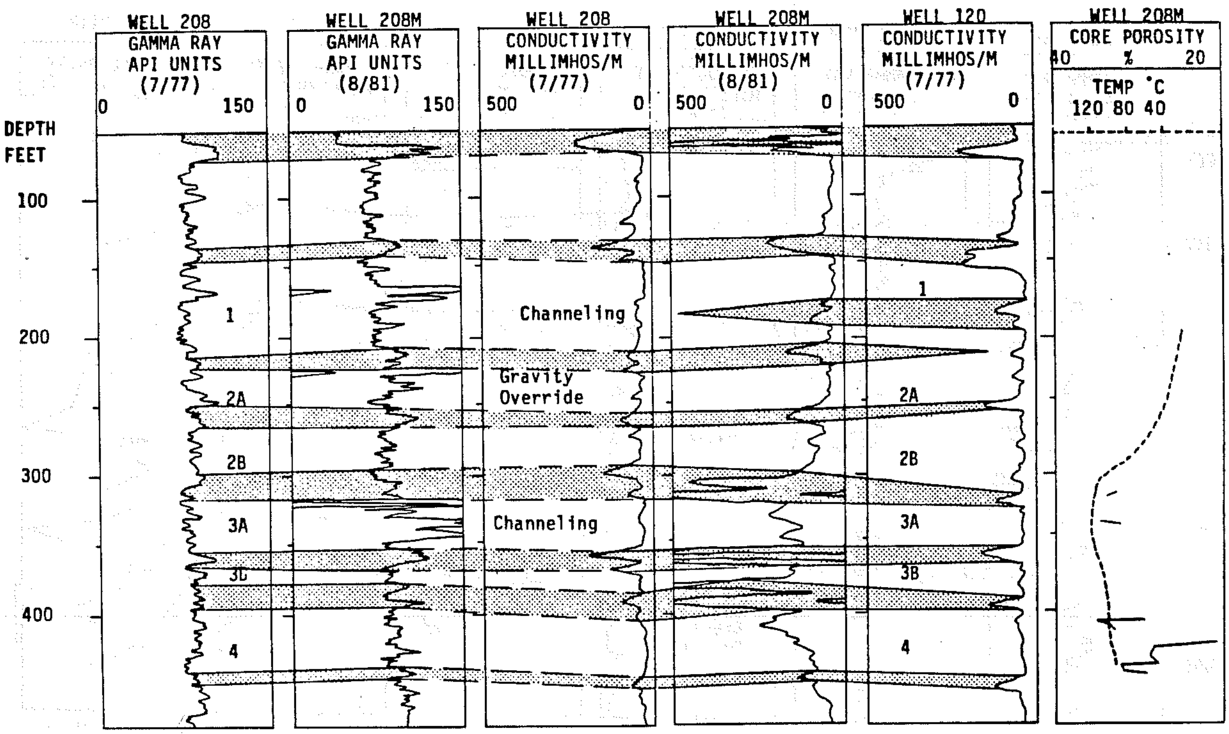


Fig. 4.5: CORRELATION BETWEEN WELLS 208 AND 120

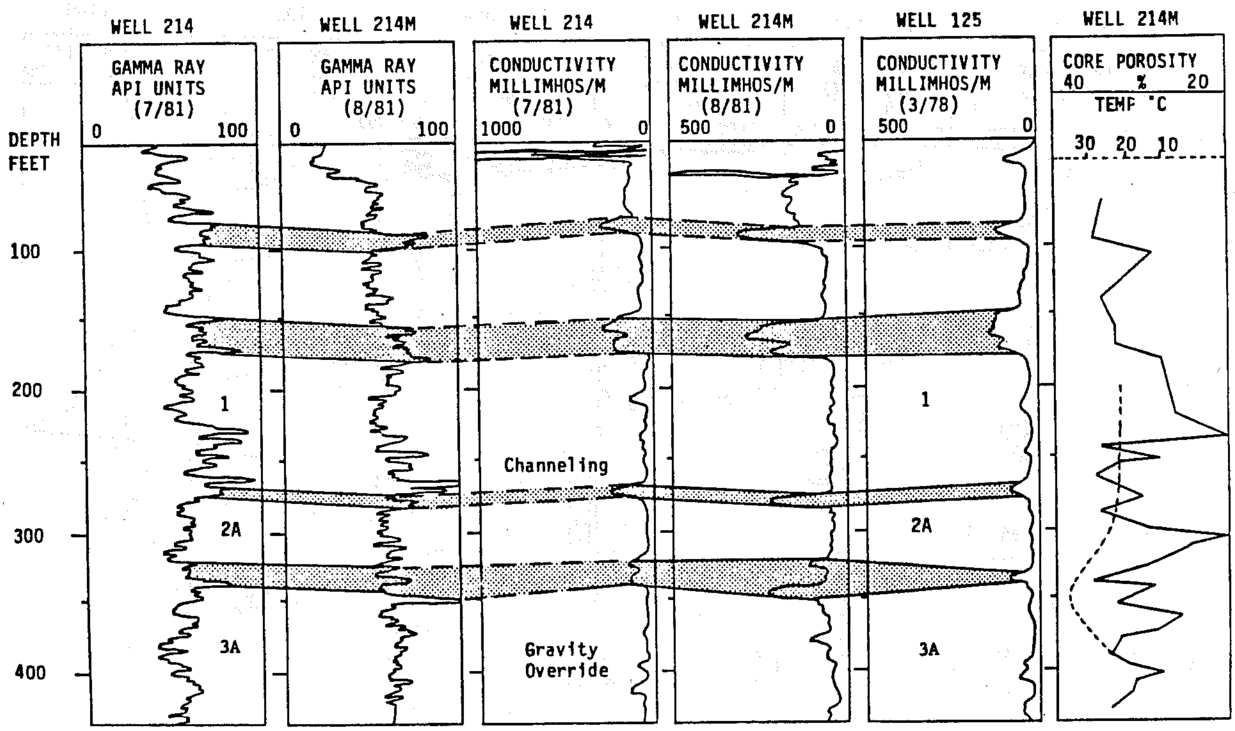


Fig. 4.6: CORRELATION BETWEEN WELLS 214 AND 125

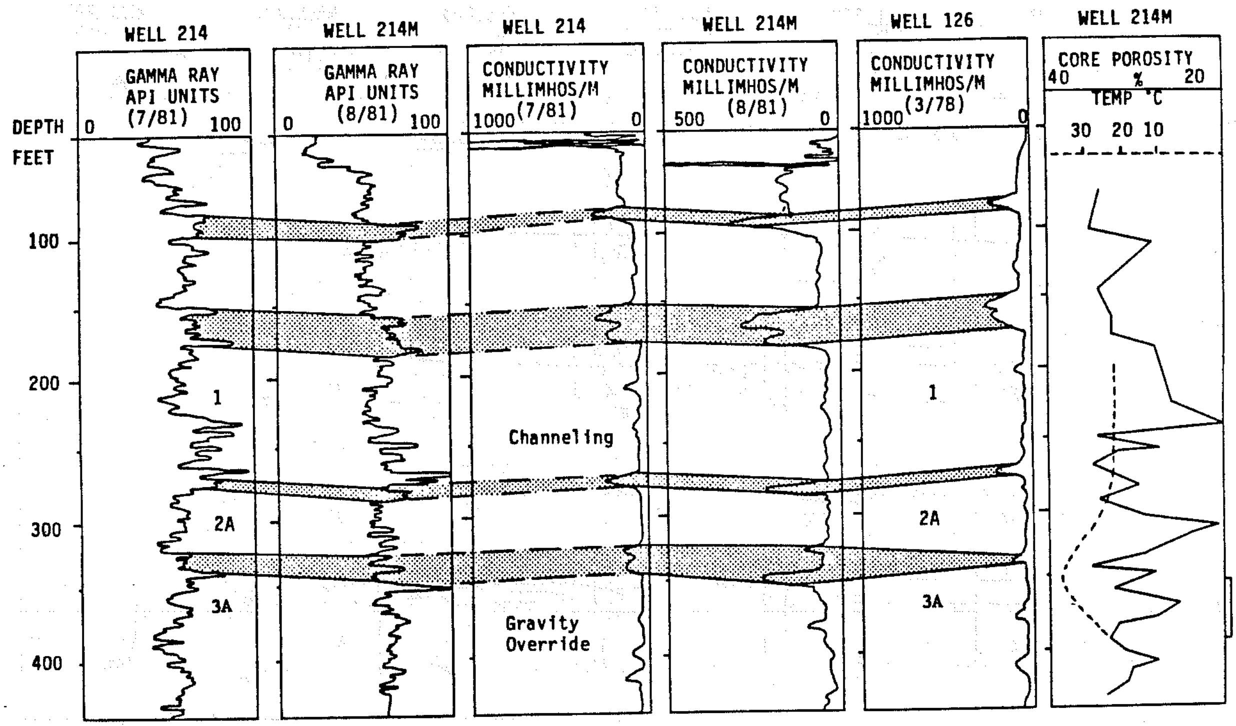


Fig. 4.7: CORRELATION BETWEEN WELLS 214 AND 126

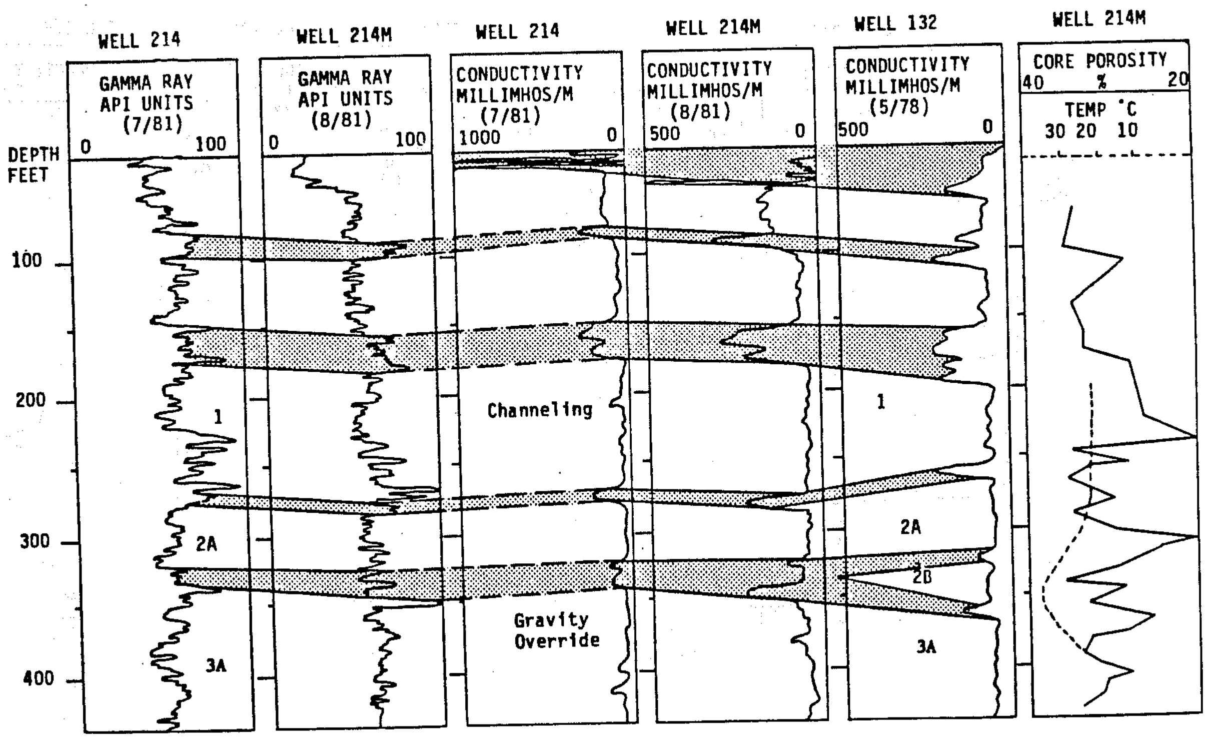


Fig. 4.8: CORRELATION BETWEEN WELLS 214 AND 132

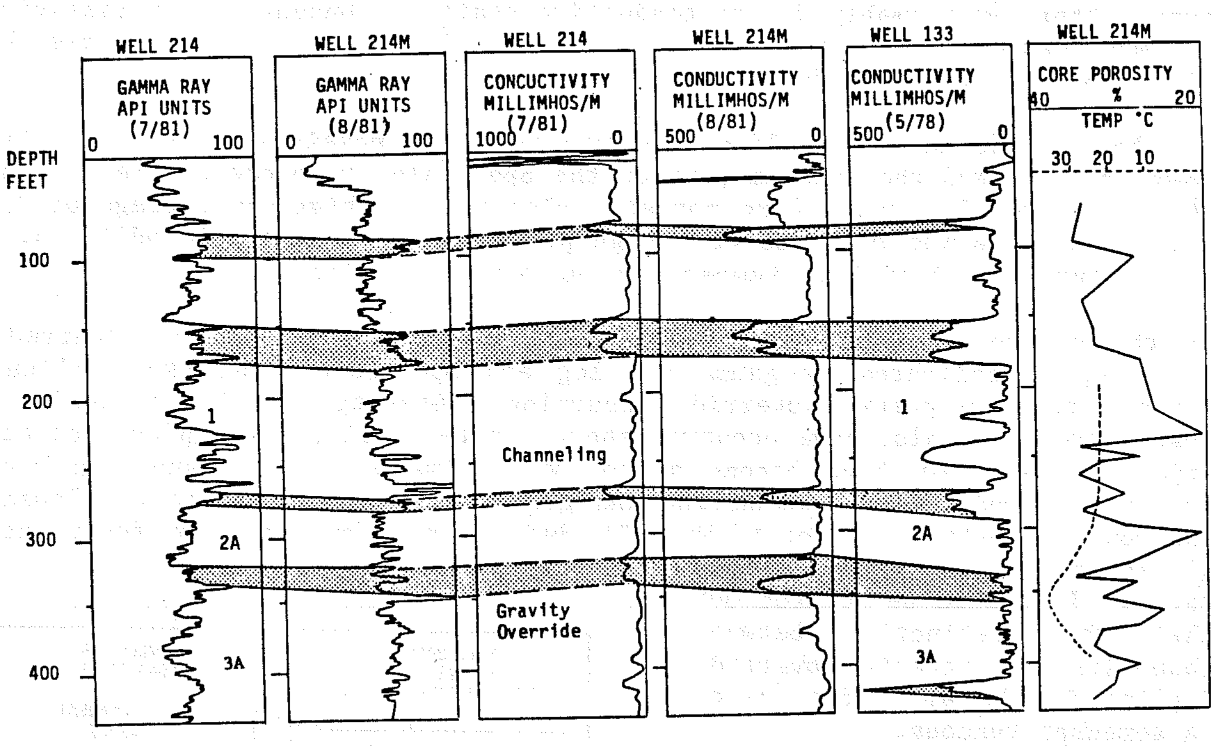


Fig. 4.9: CORRELATION BETWEEN WELLS 214 AND 133

One or more of the following criteria were used as a basis for identifying steam channeling or gravity override in the observations wells: 1) GR "spike"; 2) high electrical conductivity in shales; 3) high core porosity; and 4) high temperature.

In the test pattern, slice 1 may be undergoing steam channeling. The gamma ray response shows a "spike" in this slice. The Spectralog, which displays the gamma ray intensities ascribed to the natural abundance of uranium series, thorium series, and potassium (K40) radioactive isotopes, shows an abnormally high uranium concentration at the depth of the gamma ray spike. This is presumably the effect of leaching and redeposition of uranium salts due to the movement of steam and/or steam condensate. Similar spikes have been observed in cased-hole gamma ray logs run in several old producers in this lease and these agree with the location of the expected steam-swept slices.

In slices 2A in the test pattern, gravity override may be occurring. A gamma ray spike is observed at the top of the sand. In this slice, the gamma ray spike is caused in part by a high thorium concentration because the Spectralog shows only a moderate uranium response.

Major channeling appears to be established in slice 3A in the test pattern. Both the gamma ray log and Spectralog display a high total GR response in this slice. The temperature log shows the highest temperature occurring within this slice. The resistivity of the shales directly above and below 3A is substantially lower than the resistivity of the shales in older wells in the same pattern--presumably due to conductive heating. Unusually low resistivity of impermeable shales appears to be useful for identifying heated slices Both slices 3A and 3B are perforated for injection.

In the control pattern, slice 1 shows signs of possible steam channeling. Gamma ray log and the uranium part of the Spectralog response are very high at the bottom of the sand. Core porosity also is very high--an average of 35%--which indicates the presence of a high-permeability streak. In addition, the temperature log shows high temperature across this slice.

In the control pattern, steam channeling also appears to have occurred in slice 1, as indicated by gamma ray log and Spectralog response. Slice 3A appears to show gravity override occurring. Gravity override in 3A in the test pattern may also have occurred shortly after Well 208 was placed on steam injection, but may have become marked with time as steam channeling became more pronounced. Steam channeling and gravity override may have developed in the control pattern prior to Well 214 being placed on injection due to steam migration from adjacent patterns. It should be pointed out that the distinction between channeling and gravity override implied in the above discussion is somewhat tenuous.

After geologic layering was established by well log correlation, Carbon/Oxygen logs were analyzed qualitatively to determine vertical distribution of hydrocarbon saturation. In the test pattern, slices 1, 2A and 4 appear to be oil-rich, while slices 3B and 2B may be depleted. The carbon/oxygen (C/O) ratio and the silicon/calcium (Si/Ca) ratio inverse were normalized to coincide in the slices where no hydrocarbon saturation is present, such as in shales (Figs. 4.10 and 4.11). Slice 2B, which appears to be entirely depleted, may have been produced or may never have contained oil. Slice 3A, the major steam swept zone, shows some oil saturation remaining at the top of the sand. Reperforation into the upper slices may be warranted. By comparison, all slices in the control pattern appear to be oil-rich, which is to be expected because the pattern has been on steam injection for only about nine months. It

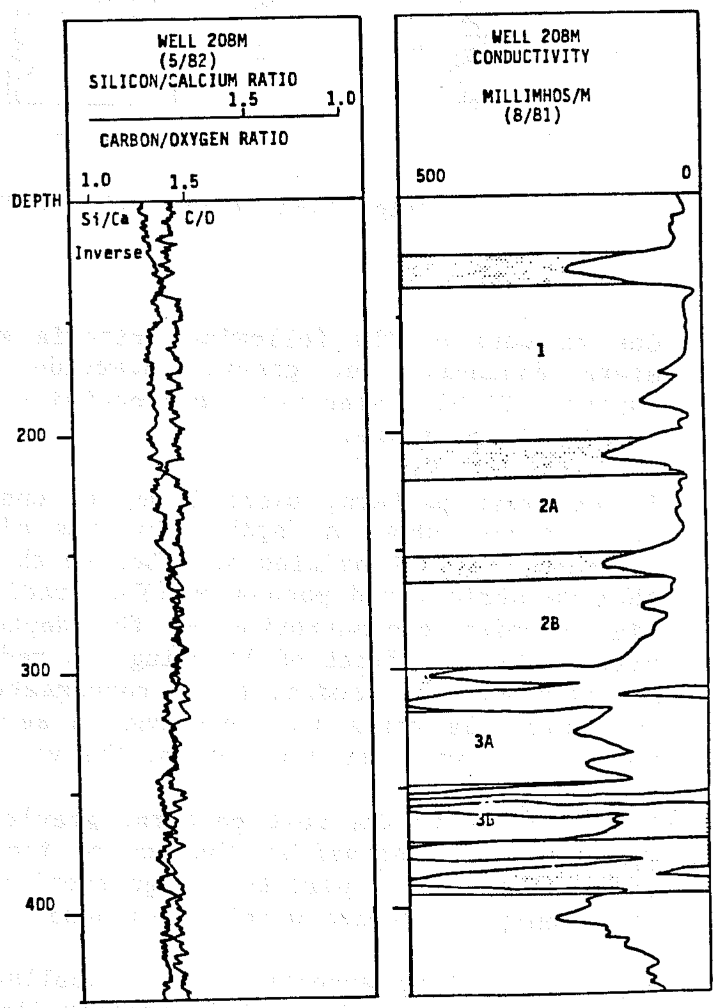


Fig. 4.10: SATURATION DISTRIBUTION IN WELL 208M

should be noted that the interpretation of steam channeling given here may apply only to the conditions around the observation wells, which may be different from those around injectors and producers.

4.3 QUANTITATIVE ANALYSIS OF CORE AND LOG DATA

Detailed computer interpretation of the well logs is underway. However, preliminary quantitative analysis for selected slices has been attempted, as outlined below.

4.3.1. Porosity Estimates

Porosity values at selected intervals for observation wells 208M and 214M were estimated from three different sources: 1) conventional whole core and sidewall core data; 2) density-neutron porosity logs; and 3) Schlumberger's computer interpretation (VOLAN). Results are shown in Tables 4.1 and 4.2.

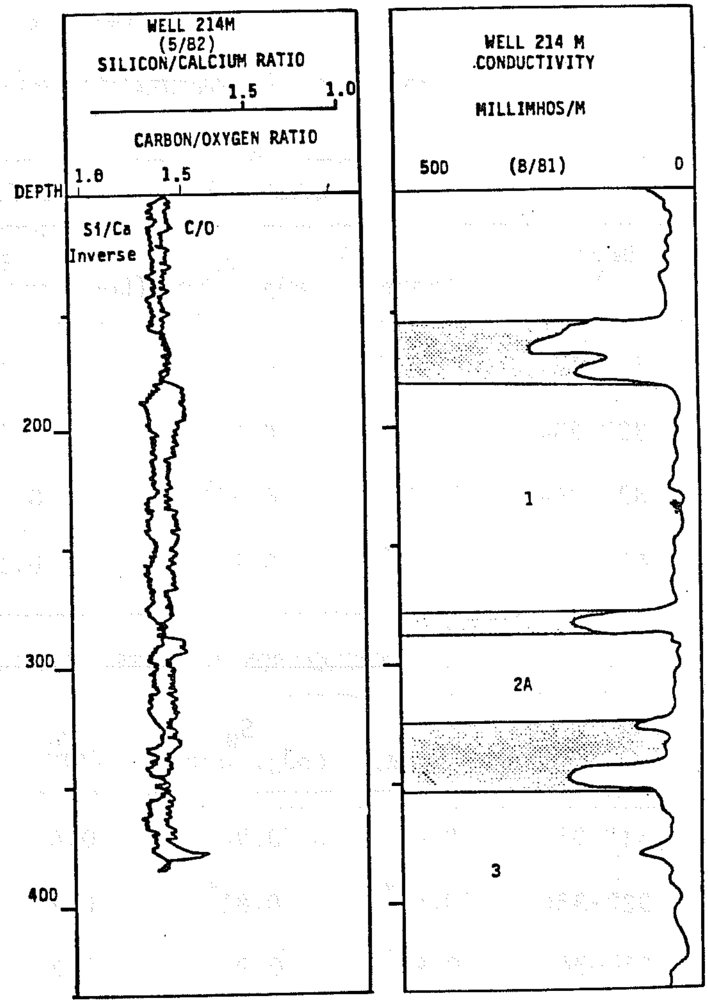


Fig. 4.11: SATURATION DISTRIBUTION IN WELL 214M

Core porosity values for Well 208M range from 23% to 29% and average 27%. For Well 214M, the range is 22% to 28%, with the average being 25%. These values were obtained by adjusting sidewall and whole core data using Elkins' method [Horner, 1982]. This technique assumes that the total pore volume in unconsolidated sand cores consists of core oil and water volume only. That is:

$$V_v = V_o + V_w \tag{4.1}$$

where:

$$V_o = S_o \phi V_b \tag{4.2}$$

and:

$$V_w = S_w \phi V_b \tag{4.3}$$

Table 4.1

POROSITY AND SATURATION ESTIMATES IN WELL 208M

COMPARISON OF POROSITY ESTIMATES

Depth, ft	ϕ (core)	ϕ (adj. core)	ϕ (Log Correlation)	ϕ (VOLAN)	ϕ (TDC Well 205)
310-314	0.33†	0.25†	0.23	0.20	
322-334	0.35†	0.29†	0.23	0.28	0.30*+†
334-344	0.33†	0.32†	0.22	0.32	0.29*+†
400-438	0.30*	0.23*	0.21	0.28	0.25*+†

COMPARISON OF WATER SATURATION ESTIMATES

Depth, ft	S_w (core)	S_w (adj. core)	S_w (EPT)	S_w (R_t)	S_w (VOLAN)	S_w TDC Well 205)
310-314	0.68	0.90†	0.65	1.00	0.90	
322-334	0.67†	0.81†	0.48	0.68	0.80	0.61*+†
334-344	0.91†	0.94†	0.57	0.54	0.90	0.67*+†
400-438	0.65*	0.85*	0.60	0.54	0.78	0.72*+†

NOTE: * indicates sidewall core, † indicates whole core

Adjusted porosity is then given by:

$$\phi_{adj} = \frac{V_v}{V_b} = S_o \phi + S_w \phi \tag{4.4}$$

By comparison, preliminary well log interpretation completed using density-neutron logs (discussed later under "Methodology of Log Analysis") shows an average porosity of approximately 22% for both observation wells, which is somewhat lower than that obtained by Elkins' method. It has been reported that in this field, core-derived porosity is often greater than log-derived values; however, the reasons for this are not well understood.

Schlumberger's computer-processed log, VOLAN (Figs. 3.1 and 3.2), indicates average values of 25% and 27% for Wells 214M and 208M. These estimates are in good agreement with those obtained by the Elkins' method and are higher than the results of this study.

Table 4.2

POROSITY ESTIMATES IN WELL 214M

Depth, ft	ϕ (core)	ϕ (adj. core)	ϕ (Log Correlation)	ϕ (VOLAN)	ϕ (TDC Well 211)
192-220	0.29	0.22	0.19	0.28	
235-249	0.35*	0.26	0.24	0.25	0.29†
257-283	0.31*	0.25	0.23	0.28	0.28*+†
295-333	0.32*+†	0.28	0.18	0.22	0.27†
337-351	0.29*	0.23	0.23	0.23	0.27*+†
359-375	0.32*+†	0.27	0.23	0.28	0.25†
395-415	0.31*	0.23	0.22	0.21	0.31†

NOTE: * indicates sidewall core, † indicates whole core

Core data for McManus Wells 205 and 211 show an average porosity of 28% for both wells [Todd, Dietrich and Chase, Inc., 1980]. Figure 1.2 shows the location of these wells relative to the control and test patterns. Adjusted core data for Wells 208M and 214M give porosities of 27% and 25%, respectively, compared to 28% for both WellS 205 and 211.

Comparison of porosity estimates seems to indicate that porosity determination for Wells 208M and 214M from density-neutron porosity logs is generally less than that obtained by other methods. The reason for this discrepancy is being investigated.

Preliminary computer interpretation of density-neutron porosity predicts an average porosity of 23% for Well 208M and 22% for Well 214M (Figs. 4.12 and 4.13) [Horner, 1982].

4.3.2 Saturation Estimates

Water saturation for Wells 208M and 214M was estimated by several different techiques: 1) conventional whole-core and sidewall-core data; 2) resistivity logs; 3) Electromagnetic Propagation Tool (EPT); and 4) Schlumberger's computer interpretation (VOLAN). In addition, Schlumberger's Gamma Ray Spectroscopy (GST) log was used to estimate water saturation in a portion of Well 214M. Results are shown in Tables 4.1 and 4.3.

Measured core water saturation was adjusted using Elkins' method, where:

$$S_{w_{adj}} = \frac{S_w \, \phi \, V_b}{\phi_{adj} \, V_v} = \frac{\phi}{\phi_{adj}} S_w \qquad (4.5)$$

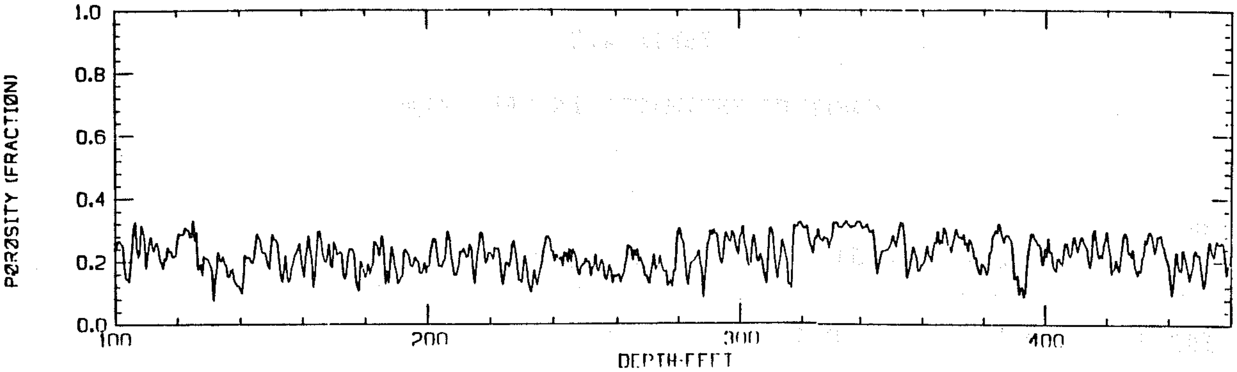


Fig. 4.12: CALCULATED POROSITY PROFILE IN WELL 208M

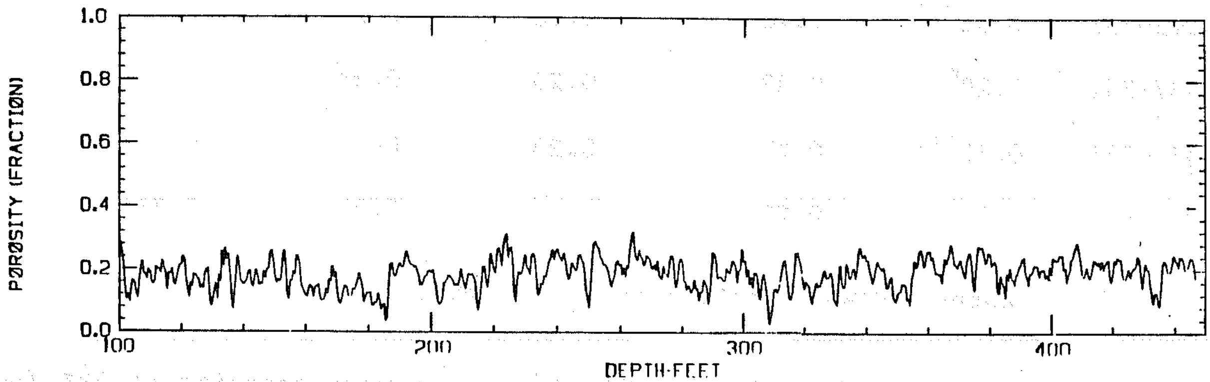


Fig. 4.13: CALCULATED POROSITY PROFILE IN WELL 214M

Table 4.3

SATURATION ESTIMATES IN WELL 214M

Depth, ft,	S_w (core)	S_w (adj. core)	S_w (EPT)	S_w (R_t)	S_w (VOLAN)	S_w (TDC) (Well 211)	S_w (GST)
192-220	0.50*	0.66	0.20	0.33	0.70		0.77
235-249	0.34*	0.46	0.50	0.40	0.65	0.46†	0.82
257-283	0.63*	0.78	0.42	0.38	0.71	0.66*+†	0.78
295-333	0.64*+†	0.73	0.19	0.30	0.73	0.73*+†	0.71
337-351	0.55*	0.69	0.49	0.60	0.80	0.69*+†	
359-375	0.67	0.79	0.57	0.69	0.63	0.77†	
395-415	0.56	0.75	0.43	0.48	0.70	0.94†	

NOTE: * indicates sidewall core, † indicates whole core.

Average water saturation obtained by this formula is 69% for Well 214M and 88% for Well 208M. By comparison, resistivity logs yield water saturations of 45% and 69% for 214M and 208M, respectively, which are considerably lower than those obtained by Elkins' method.

Measurements from Schlumberger's Electromagnetic Propagation Tool (EPT) provided the third technique for evaluation of formation water saturation. Agreement between the resistivity and EPT-derived measurements of water saturation in 214M is good. The EPT log predicts a water saturation of 40% in Well 214M compared to 45% predicted by the resisitivity log. Agreement for Well 208M, however, is not as good. Water saturation calculated from the EPT log is 58%, which is appreciably lower than the 69% derived by the resistivity log.

Schlumberger's computer interpretation (VOLAN) indicates average water saturations of about 85% in Well 208M and 70% in Well 214M. Core data from McManus Wells 205 and 211 show an average water saturation of 67% and 71%, respectively [Horner, 1982]. Lastly, in the interval of Well 214 in which the GST log was run, water saturation appears to be 77%.

In general, water saturation in Well 208M is about 20% greater than that in Well 214M. This appears to be reasonable because 208M has been on steam injection approximately three years longer than 214M. Carbon/Oxygen logs also verify that oil saturation in Well 208M is less than that in 214M.

Preliminary computer-calculated oil saturation for Well 208M is shown in Fig. 4.14; oil-in-place for Wells 208M and 214M is shown in Figs. 4.15 and 4.16, respectively [Horner, 1982]. Oil-in-place in Well 208M is about 500 bbl/ac-ft, compared to about 1000 bbl/ac-ft in Well 214M. However, these computed values are only preliminary estimates.

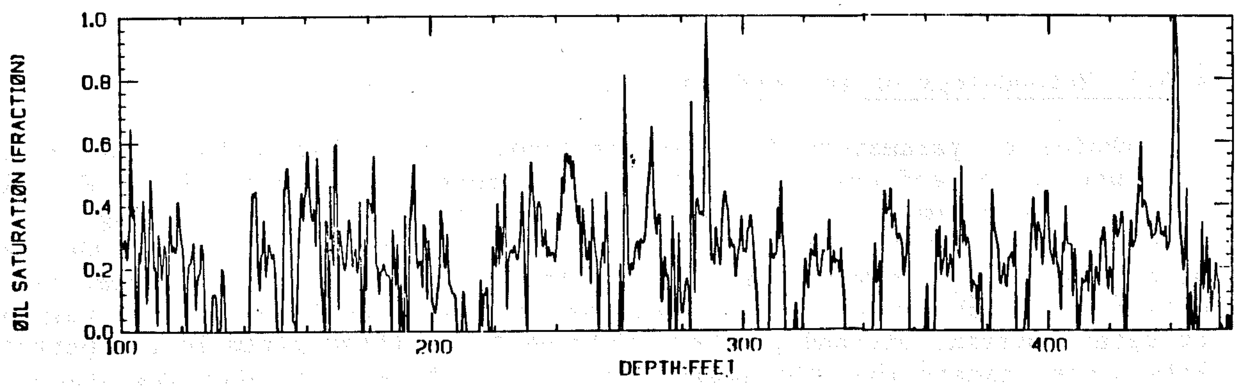


Fig. 4.14: CALCULATED OIL SATURATION PROFILE IN WELL 208M

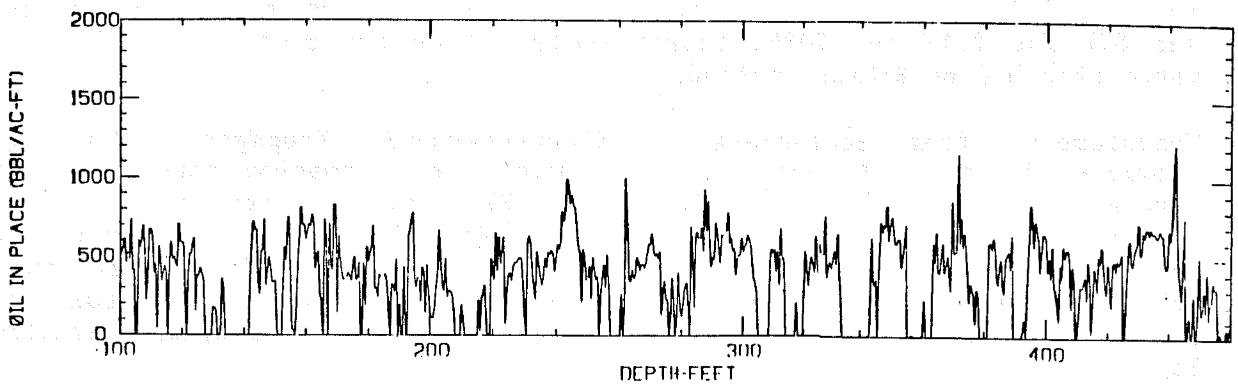


Fig. 4.15: CALCULATED OIL-IN-PLACE PROFILE IN WELL 208M

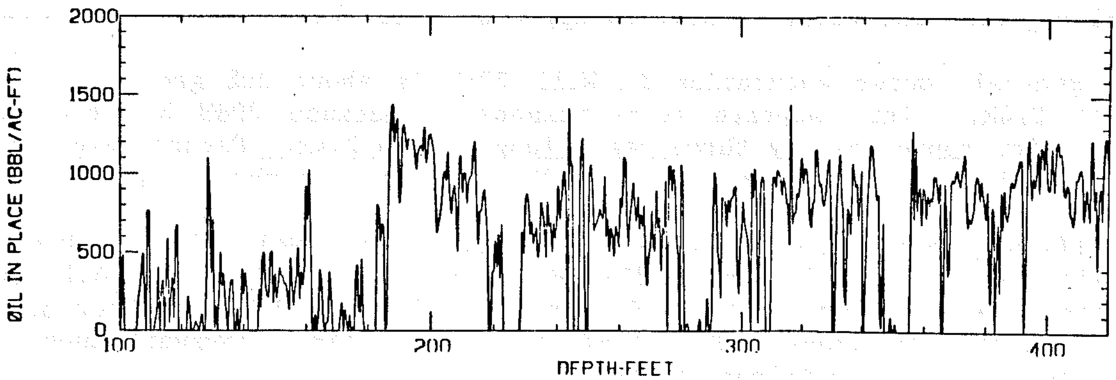


Fig. 4.16: CALCULATED OIL-IN-PLACE PROFILE IN WELL 214M

4.3.3 Methodology of Log Analysis

The choice of parameters for the responses of the log-to-formation matrix, oil, water, gas and shale is critical to a correct interpretation. Normally, the various parameters are determined from cross-plots and histograms. A cross-plot of density-porosity versus neutron-porosity determines the value of ϕ_{Dsh} and ϕ_{Nsh}, respectively. Alternatively, the shale parameters are estimated approximately from the response of nearby shale beds. The responses of water, matrix, oil and gas were assumed to be those given in the petroleum literature, except that the resistivity of the formation water was assumed to be that of a produced-water sample.

A summary of the preliminary parameters used is given in Table 4.4 and the response equations and the procedure used are discussed below.

Table 4.4

PARAMETERS USED IN PRELIMINARY WELL LOG INTERPRETATION

	EPT LOG
Component	Interval Transit Time (ns/M)
Shale (T_{psh})	19 (214M) 20 (208M)
Matrix (sandstone) (t_{pma})	7.2
Oil or gas (t_{ph})	4.9
Water (t_{pw})	28.4 at 100°F $t_{pw} = \frac{20 \times 710 - °F/3}{444 + °F/3}$
	TDT LOG
Component	Capture Cross-Section (Capture Units)
Shale (Σ_{sh})	27
Matrix (sandstone) (Σ_{ma})	10
Oil (Σ_h)	21
Gas (Σ_g)	0
Water (Σ_w)	22
	Resistivity
Archie constant (a)	0.81
Water resistivity (R_w)	12ΩM
Shale resistivity (R_{sh})	6ΩM
Shale resistivity in 208M below 300 feet	2ΩM
	Porosity
Neutron porosity of shale	0.54
Density porosity of shale	0.27

A total shale relation was used to obtain the water saturation in the uninvaded zone:

$$S_w = \frac{aR_w(1 - V_{sh})}{2\phi^2} \left\{ \sqrt{\frac{4\phi^2}{aR_w(1 - V_{sh})} \frac{1}{R_t} + \frac{V_{sh}}{R_{sh}}} - \left(\frac{V_{sh}}{R_{sh}}\right)^2 \right\} \qquad (4.6)$$

where R_t and R_{sh} were derived from the Dual Induction-SFL log. Then, ϕ and V_{sh} were calculated from density-neutron and pulsed-neutron logs as follows. If no gas is present, ϕ and V_{sh} are obtained by the simultaneous solution of:

$$\phi_N = \phi + V_{sh}\phi_{Nsh} \qquad (4.7)$$

and:

$$\phi_D = \phi + V_{sh}\phi_{Dsh} \qquad (4.8)$$

If gas is present, ϕ, V_{sh} and S_g are calculated from:

$$\phi_N = \phi(1 - S_g) + V_{sh}\phi_{Nsh} + \phi\phi_{Nh}S_g - \Delta\phi_{Nex} \qquad (4.9)$$

$$\phi_D = \phi(1 - S_g) + V_{sh}\phi_{Dsh} + \phi\phi_{Dh}S_g \qquad (4.10)$$

and:

$$\Sigma = \phi(1 - S_g)\Sigma_w + (1 - \phi - V_{sh})\Sigma_{ma} + V_{sh}\Sigma_{sh} \qquad (4.11)$$

For a gas, ϕ_{Dh} = 12/7 (zero gas density assumed):

$$\Delta\phi_{Nex} = 0.05$$

An estimate of water saturation may also be otained from EPT. The tool has a shallow depth of investigation, but because the depth of invasion is small, it is likely to read the virgin formation water saturation.

$$t_p = \phi S_w t_{pw} + \phi(S_o + S_g)t_{ph} + V_{sh}t_{psh} + (1 - \phi - V_{sh})t_{pma} \qquad (4.12)$$

Therefore:

$$S_w = \frac{t_p - V_{sh}(t_{psh} - t_{pma}) - t_{pma} + \phi(t_{pma} - t_{ph})}{\phi(t_{pw} - t_{ph})} \qquad (4.13)$$

A more rigorous computer analysis of digital log data is underway.

4.4 TRACER RESPONSE ANALYSIS

Surveying of observation Well 208M and 214M with USGS's spectral gamma ray log during addition of Krypton-85 to steam injectors 208 and 214 showed no detectable response at the observation wells. The lack of tracer response may be due to one of three possibilities: 1) the tracer passed by before the logging tool was positioned in the wellbore; 2) the tracer did not pass by due to too low a velocity of tracer front, bypassing of the observation well by the tracer front, or total adsorption of the tracer on the rock; or 3) the tracer passed by, but the tracer concentration was too low to be detected. However, Krypton-85 and sulfur hexafluoride were detected in production well 120. The analysis of this tracer response has not been completed. No tritium response was observed in any of the producers.

Analysis of produced fluid and vapor samples gathered from the producing wells in each pattern indicated that the concentrations measured were zero or nearly zero with respect to the detection limit. Injection of radioactive tracers at the maximum level allowable by the state of California, as adopted in this case, is probably insufficient to produce a measurable tracer response in this reservoir. Attempts to inject a radioactive tracer with the surfactant were abandoned due to the high probability that this tracer test would also be unsuccessful.

Non-volatile chemical tracers were considered by SUPRI at the time the radioactive tracer survey was being designed, but the idea was rejected because the mechanism by which non-volatile tracers are carried by steam is not well understood. Such tracers, being non-volatile, can not be carried in the steam phase except by entrainment of droplets of water. CORCO, however, reportedly has used non-volatile chemical tracers (for example, sodium nitrate and sodium bromide) to determine steam flow patterns in a similar formation in the North Kern Front field and claims to have obtained reasonable correlation of tracer response with known formation characteristics. A chemical tracer survey was initiated. Non-volative tracers are inexpensive (about a tenth the cost of radioactive surveys), and CORCO had apparent success with non-volatile tracers in similar formations. This procedure was initiated to complement the radioactive tracer survey.

Figures 4.17 through 4.24 show the tracer response (before the injection of the Suntech IV slug) in the producing wells in the test pattern (Wells 114, 119 and 120) and control pattern (Wells 125, 126, 132 and 133) for June 1982. Strong tracer response occurred in Wells 114 and 126, which are structurally most up-dip in the test and control patterns, respectively. Both tracer curves appear to contain two tracer peaks, which may indicate tracer flow through two different sand layers in the formation. A strong tracer response is also exhibited by Well 120, which is not the most structurally up-dip well in the test pattern. This strong tracer response probably occurred because at Well 120, slice 3A--the major steam-swept slice--is perforated for production and the continuous impermeable shale directly above 3A probably prevented the movement of tracer into upper parts of the reservoir. Figures 4.25 through 4.32 show the tracer responses in Wells 113B, 114, 119, 120, 125, 126, 132 and 113, respectively, after the second tracer injection in August 1982, following completion of the first Suntech IV slug injection. Comparison of Figs. 4.17 through 4.32 indicated that as a result of the injection of the Suntech IV slug, steam flow to producer Well 120 was substantially reduced, while that to Well 114 was significantly increased. Further analyses of the data are being conducted.

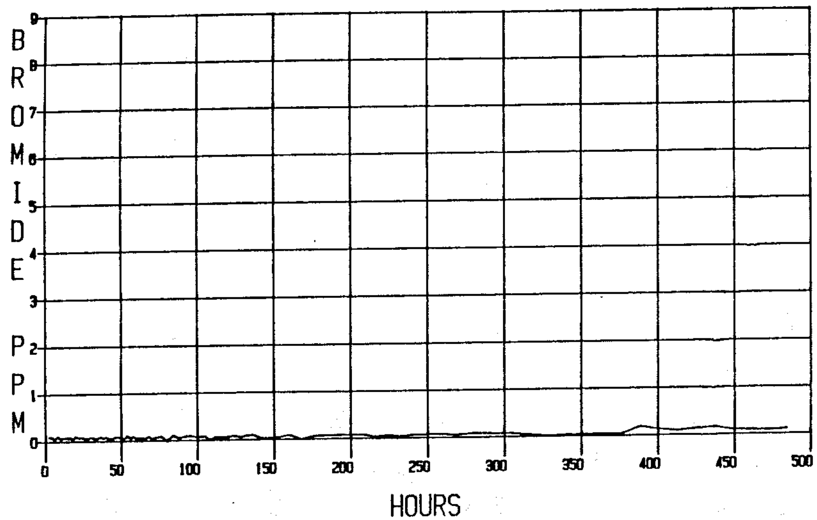


Fig. 4.17: BROMIDE TRACER BEFORE SLUG #1, WELL 113B, JUNE 1982

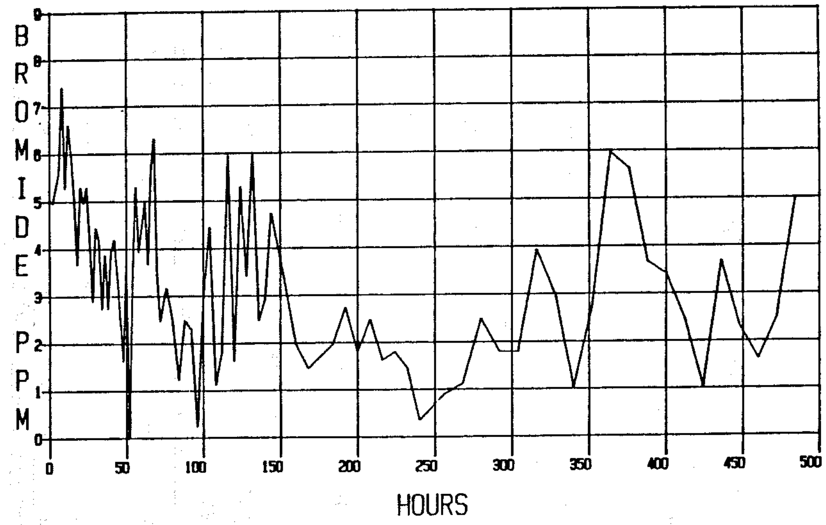


Fig. 4.18: BROMIDE TRACER BEFORE SLUG #1, WELL 114, JUNE 1982

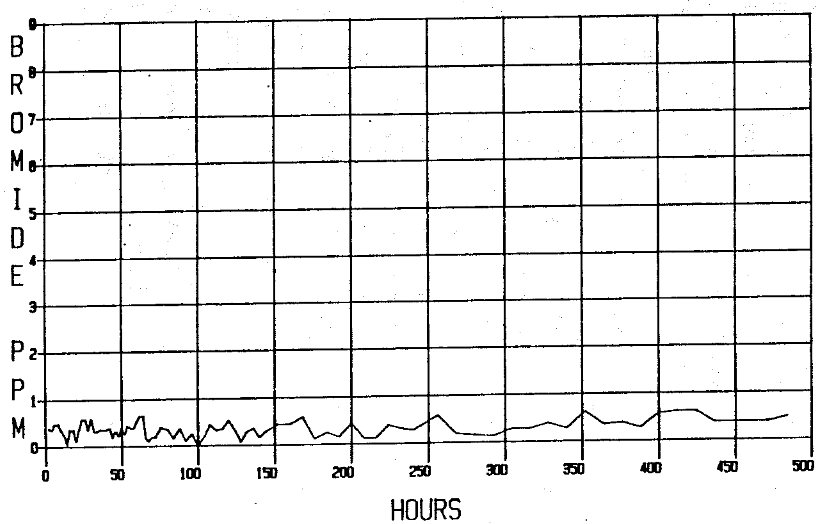


Fig. 4.19: BROMIDE TRACER BEFORE SLUG #1, WELL 119, JUNE 1982

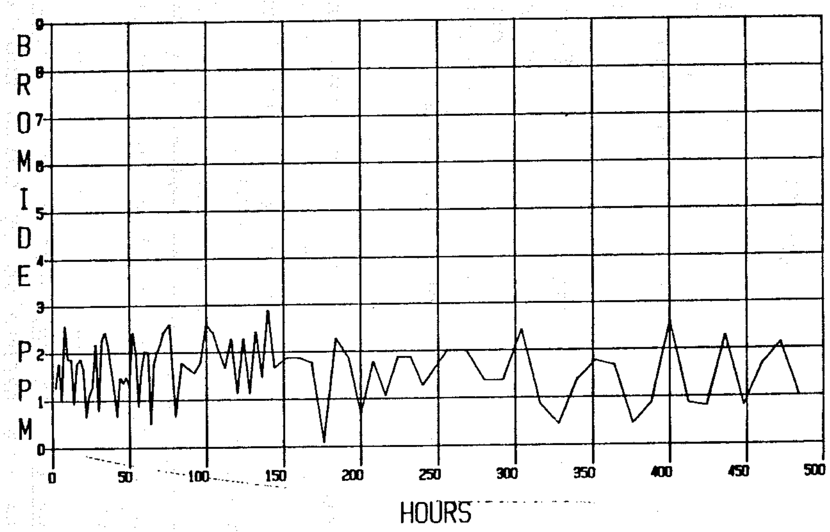


Fig. 4.20: BROMIDE TRACER BEFORE SLUG #1, WELL 120, JUNE 1982

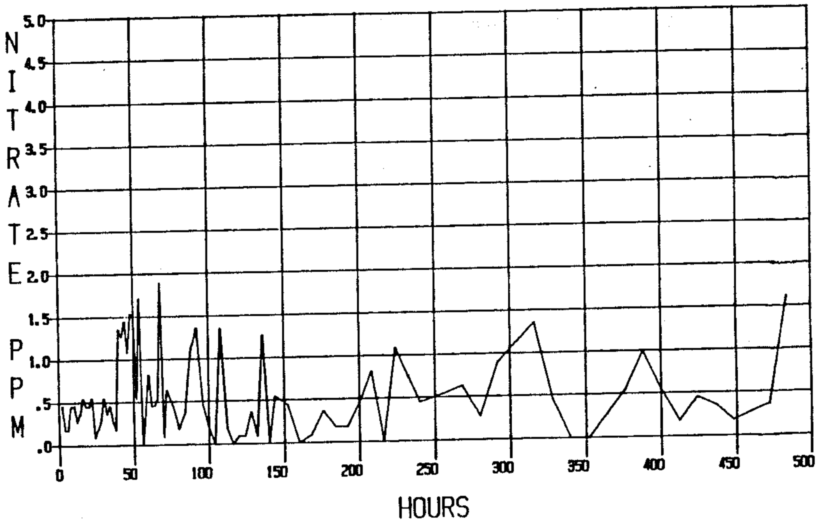


Fig. 4.21: NITRATE TRACER BEFORE SLUG #1, WELL 125, JUNE 1982

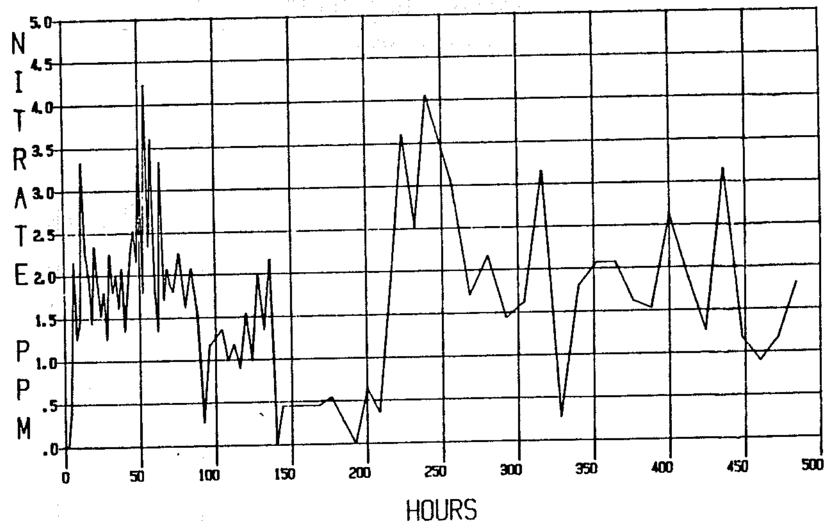


Fig. 4.22: NITRATE TRACER BEFORE SLUG #1, WELL 126, JUNE 1982

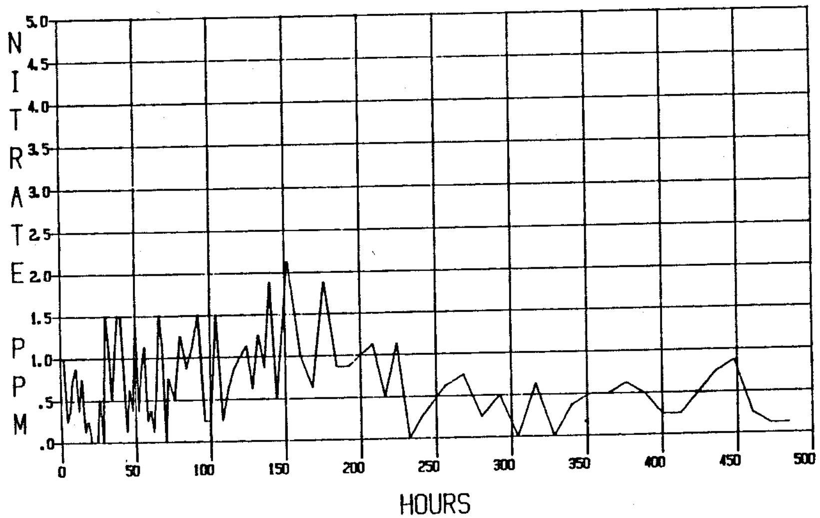


Fig. 4.23: NITRATE TRACER BEFORE SLUG #1, WELL 132, JUNE 1982

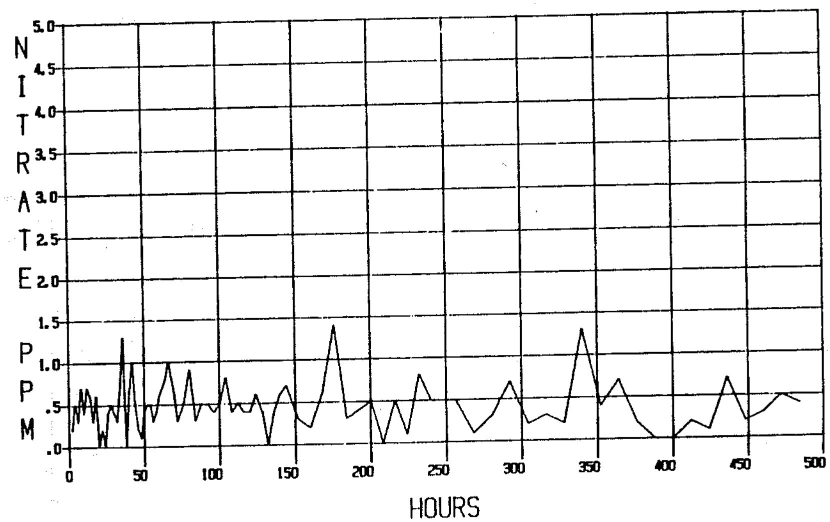


Fig. 4.24: NITRATE TRACER BEFORE SLUG #1, WELL 133, JUNE 1982

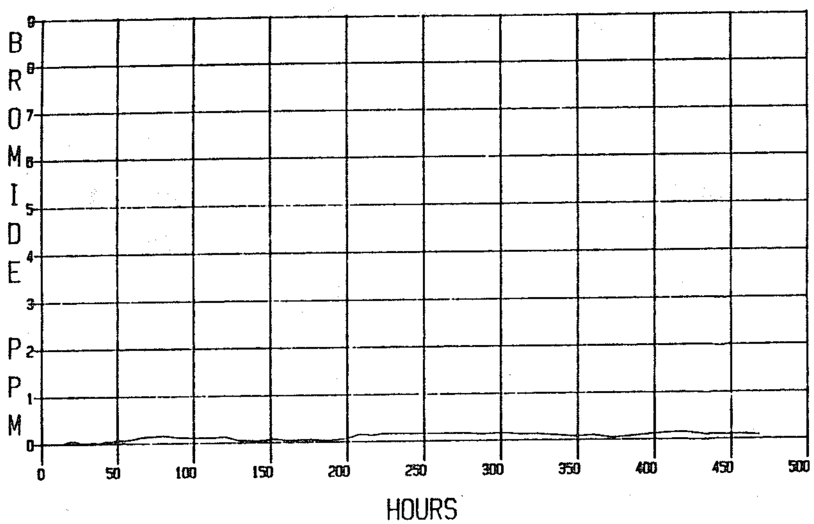


Fig. 4.25: BROMIDE TRACER AFTER SLUG #1, WELL 11B, AUGUST 1982

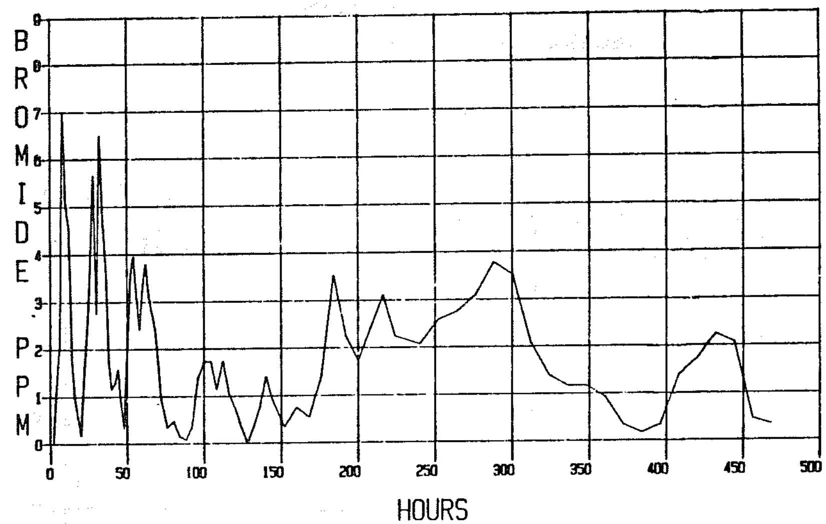


Fig. 4.26: BROMIDE TRACER AFTER SLUG #1, WELL 114, AUGUST 1982

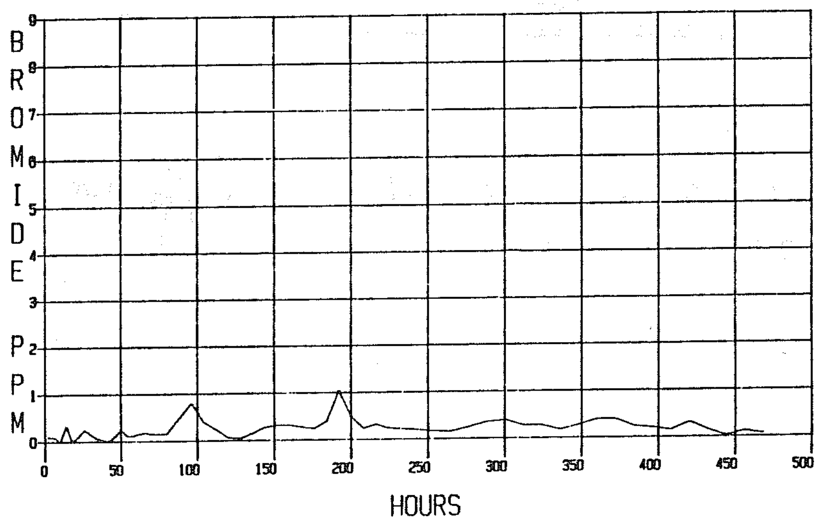


Fig. 4.27: BROMIDE TRACER AFTER SLUG #1, WELL 119, AUGUST 1982

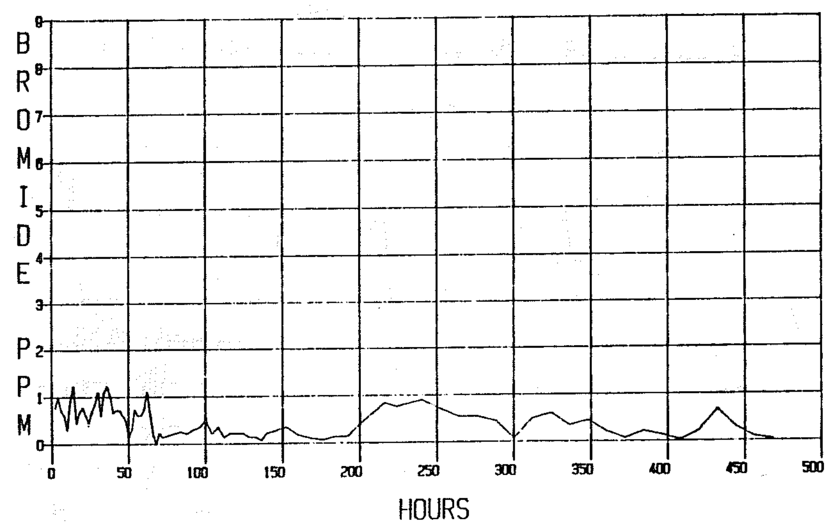


Fig. 4.28: BROMIDE TRACER AFTER SLUG #1, WELL 120, AUGUST 1982

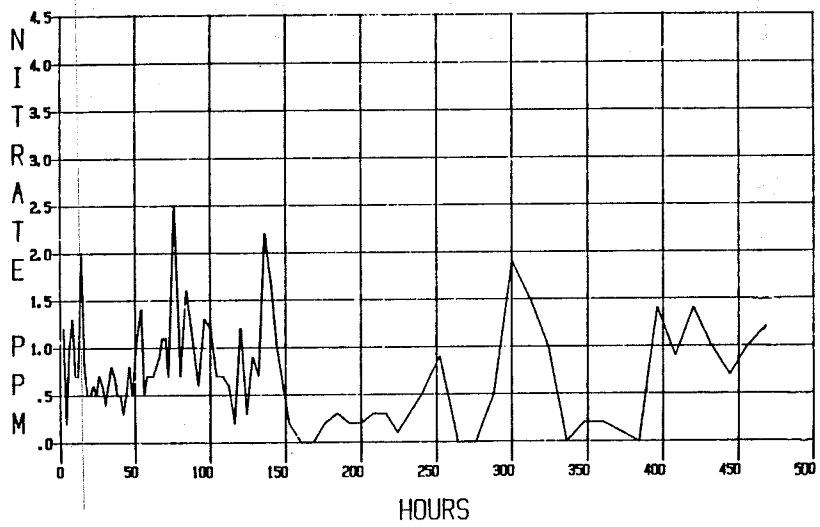


Fig. 4.29: NITRATE TRACER AFTER SLUG #1, WELL 125, AUGUST 1982

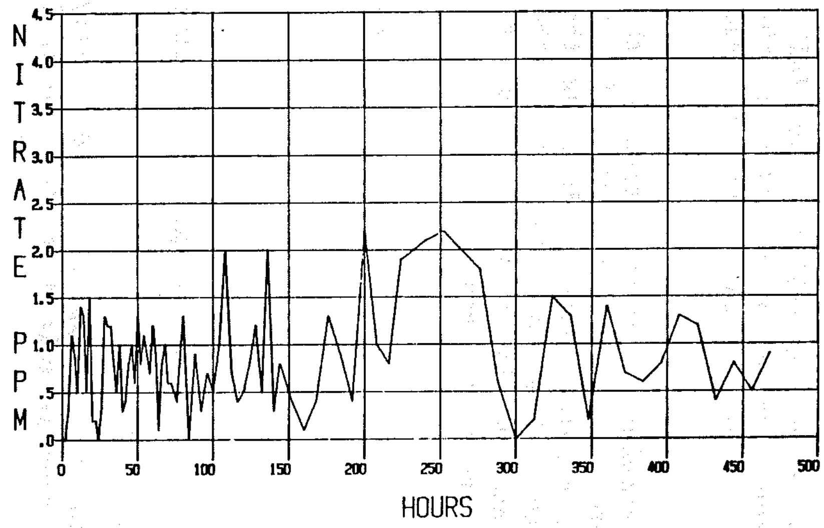


Fig. 4.30: NITRATE TRACER AFTER SLUG #1, WELL 126, AUGUST 1982

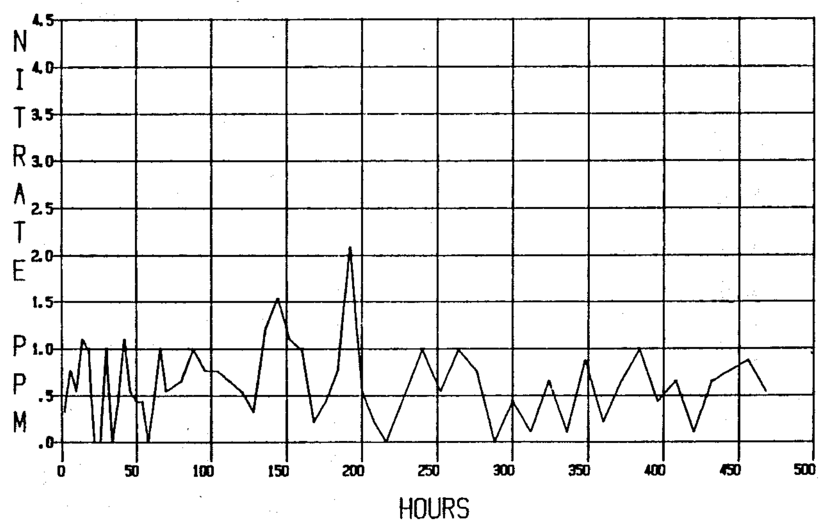


Fig. 4.31: NITRATE TRACER AFTER SLUG #1, WELL 132, AUGUST 1982

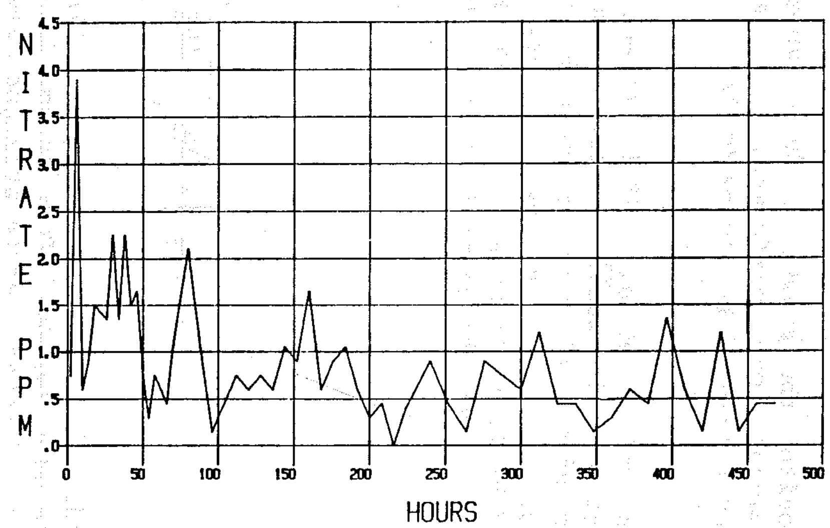


Fig. 4.32: NITRATE TRACER AFTER SLUG #1, WELL 133, AUGUST 1982

4.5 PRESSURE FALL-OFF ANALYSIS

To monitor the growth of the steam-swept zone, injection well pressure fall-off surveys were performed. Estimation of swept volume is possible by the theory presented by Eggenschwiler et al. [1980] using the guidelines proposed by Walsh et al. [1981].

Eggenschwiler et al. [1980] showed that a pressure transient test at the injection well would exhibit a small wellbore storage effect acting for a short period of time followed by a semi-log straight line, indicating the conductivity of the swept zone. From the slope of this line, the permeability-thickness of the swept zone, kh, and the skin factor, s, could be computed from the commonly used infinite-acting reservoir equations:

$$kh = \frac{162.6\ qB\mu}{m} \tag{4.14}$$

and:

$$s = 1.1513 \left[\left(\frac{p_{wf} - p_{1hr}}{m} \right) - \log \left(\frac{k}{\phi\ \mu\ c_t\ r_w^2} \right) + 3.23 \right] \tag{4.15}$$

Immediately after the semi-log straight line period, an apparent pseudo-steady state flow begins. Pore volume in the swept zone is related to the slope, of the pseudo-steady state straight line by:

$$V_p = \frac{q_s\ B_s}{c_t\ m'} \tag{4.16}$$

The compressibility is defined at constant enthalpy as suggested by Grant and Sorey [1979] and Walsh et al. [1981]:

$$c_t = 0.18513 \frac{(\rho C')}{\phi} \left(\frac{\rho_w - \rho_s}{L_v\ \rho_w\ \rho_s} \right)^2 (T + 460) \tag{4.17}$$

where:

$$(\rho C') = (1 - \phi)\rho_r C_r + \phi S_w \rho_w C_w \tag{4.18}$$

Walsh et al. [1981] proposed guidelines to evaluate pressure falloff tests for steamflood projects based on the principles outlined by Eggenschwiler et al. [1980]. Recently, Messner and Williams [1982] applied this analytic technique to a program of pressure transient testing on steam injection wells. However, the determination of the average pressure in the steam zone and selection of the correct semi-log straight line were inaccurate in their paper.

Walsh et al.'s [1981] step-by-step procedure for quantitatively interpreting pressure fall-off testing in steamfloods has been applied to the pressure fall-off data obtained at the SUPRI field test site.

Figures 4.33 and 4.34 show the semi-log (p_{ws} versus log Δt) and Cartesian plots of pressure versus shut-in time fore Well 208 for the October 1981 test, while Figs. 4.35 and 4.36 show the same curves for Well 214 for the October 1982 test. The February 1982 data are plotted in Figs. 4.37 through 4.40, while the May 1982 data are shown in Figs. 4.41 through 4.44. Examination of the semi-log graphs (Figs. 4.33, 4.35, 4.37, 4.39, 4.41 and 4.43) for both wells shows that the initial period of damage and wellbore storage is short and wellbore storage itself is small. Due to these factors, early-time type-curve matching should not be used to estimate the beginning of the semi-log straight line. According to Ramey [1982], the semi-log straight line should begin around 0.1 hour and last until Δt = 1 to 2 hours. These guidelines are based on examination of numerous field cases of pressure fall-off tests. The semi-log plots for Wells 208 and 214 fit these guidelines reasonably well. From the slopes of these semi-log lines, the permeability-thickness products and skin factors were calculated using Eqs. 4.14 and 4.15. A prerequisite for these calculations is the determination of the average reservoir pressure behind the steam front from the semi-log plot of pressures versus shut-in time. The pressure should not be read from the beginning of the straight line period, as suggested by Messner and Williams [1982]. Approximating the average reservoir pressure in this manner results in a pressure that is too high. The true average pressure should be obtained by weighting the recorded pressures lying on the semi-log line by volume (r^2 or t^2) and taking the weighted average of these pressures. Since most of the semi-log lines are short, visual averaging was used with heavier weighting of the later pressure values.

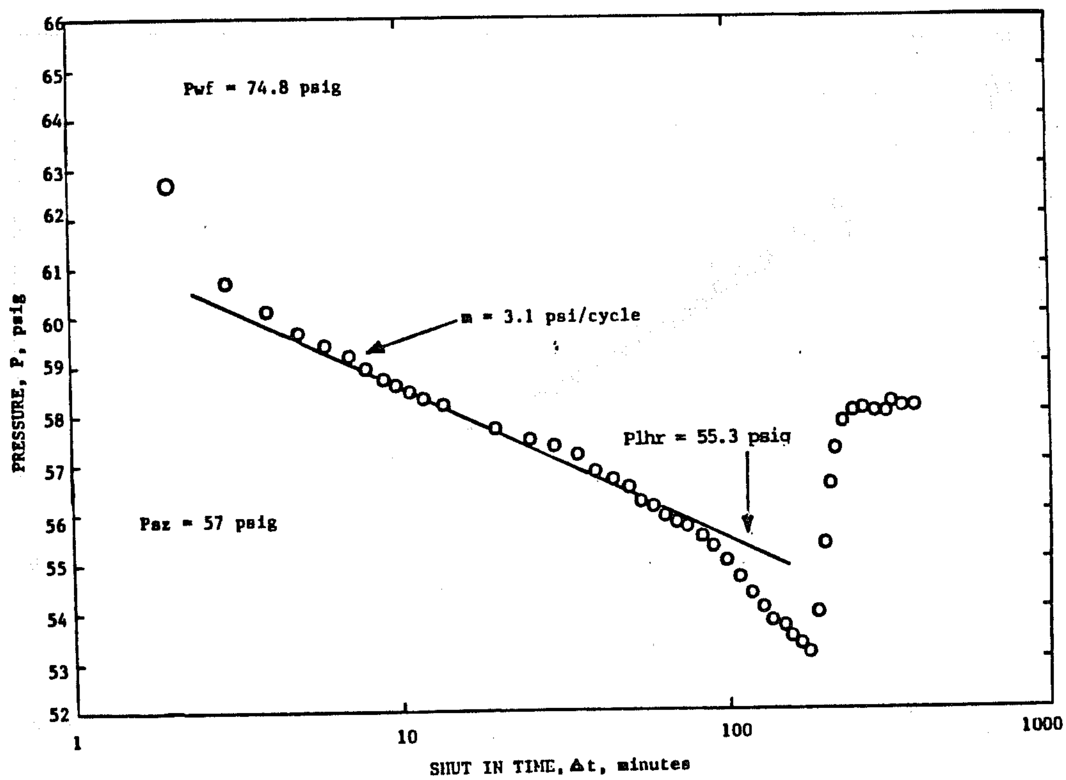


Fig. 4.33: SEMI-LOG PLOT OF PRESSURE FALL-OFF DATA, WELL 208, OCT. 1981

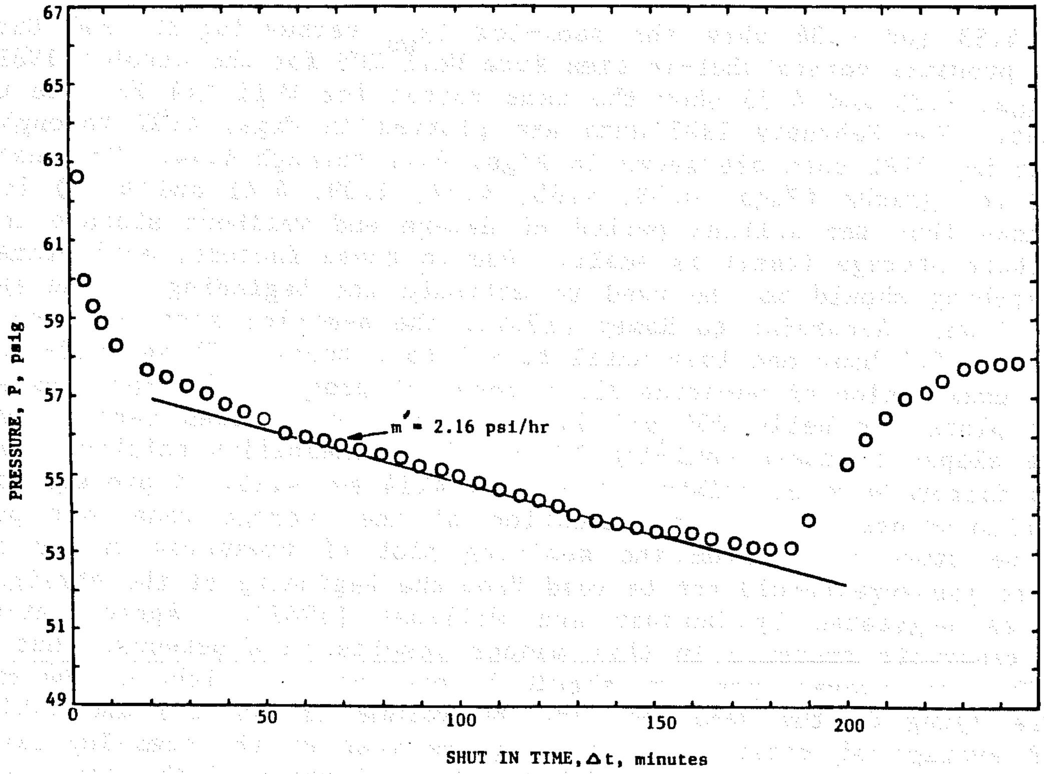


Fig. 4.34: CARTESIAN PLOT OF PRESSURE FALL-OFF DATA, WELL 208, OCT. 1981

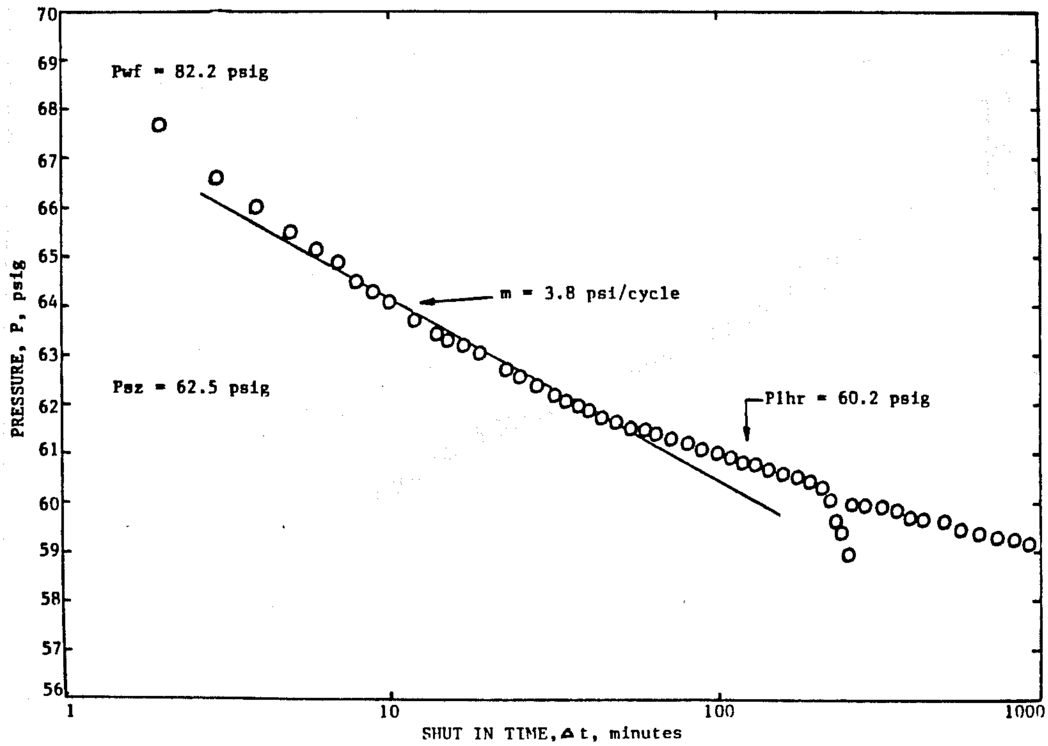


Fig. 4.35: SEMI-LOG PLOT OF PRESSURE FALL-OFF DATA, WELL 214, OCT. 1981

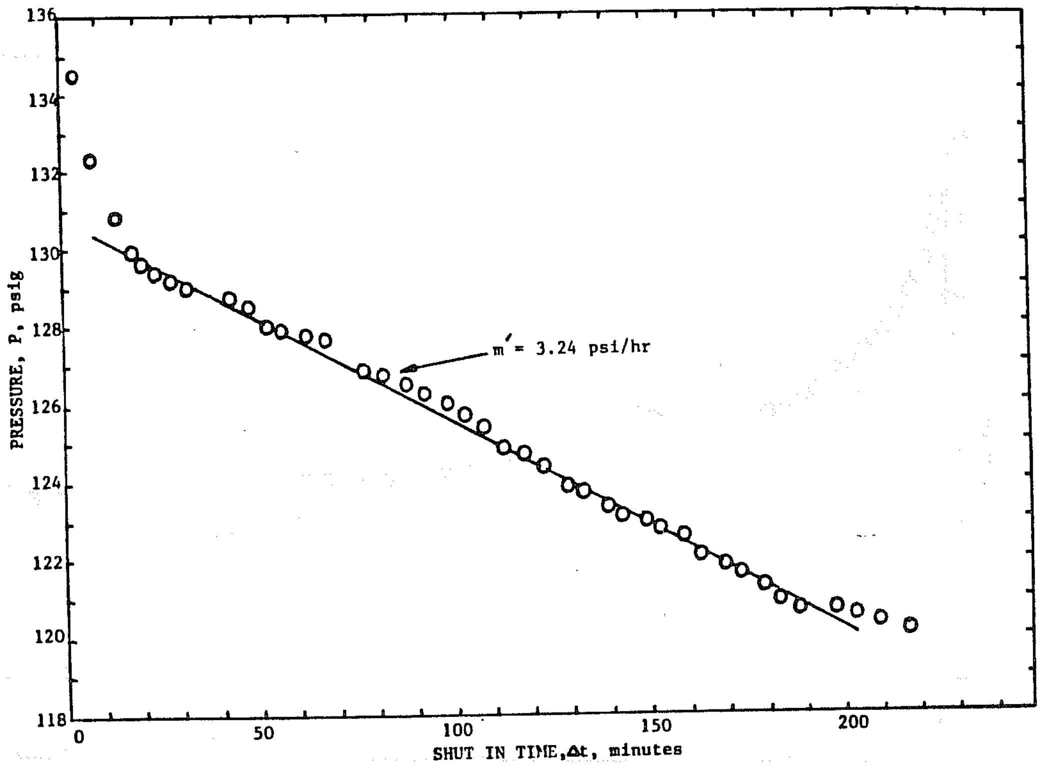


Fig. 4.36: CARTESIAN PLOT OF PRESSURE FALL-OFF DATA, WELL 214, OCT. 1981

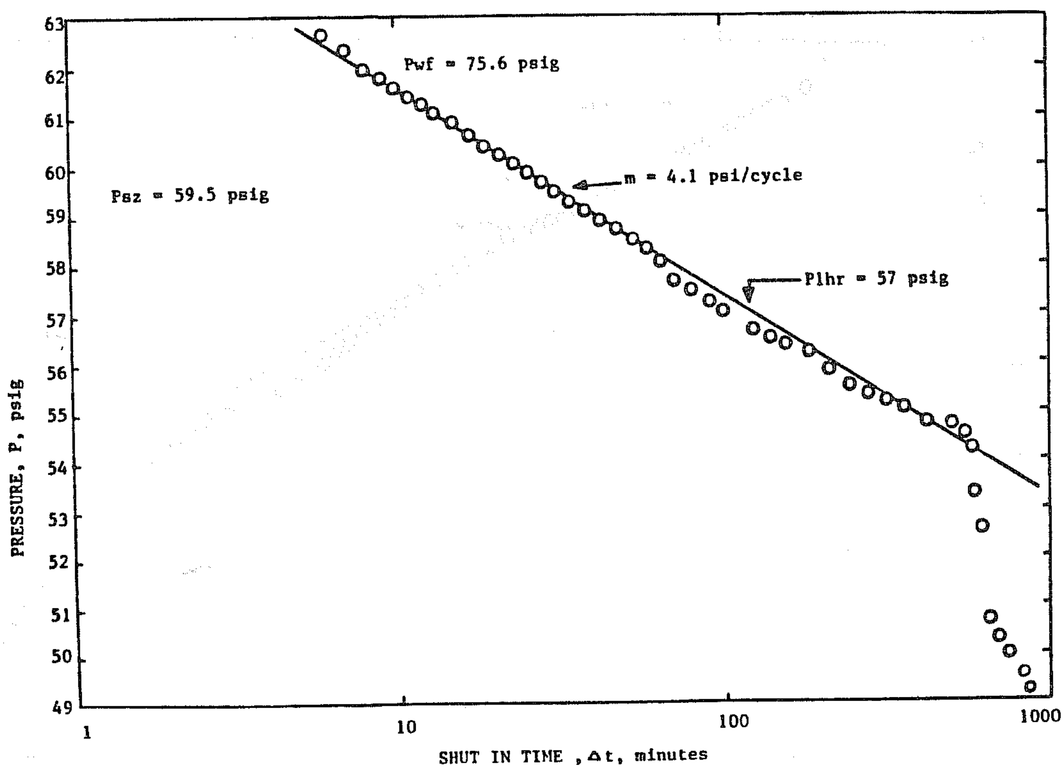


Fig. 4.37: SEMI-LOG PLOT OF PRESSURE FALL-OFF DATA, WELL 208, FEB. 1982

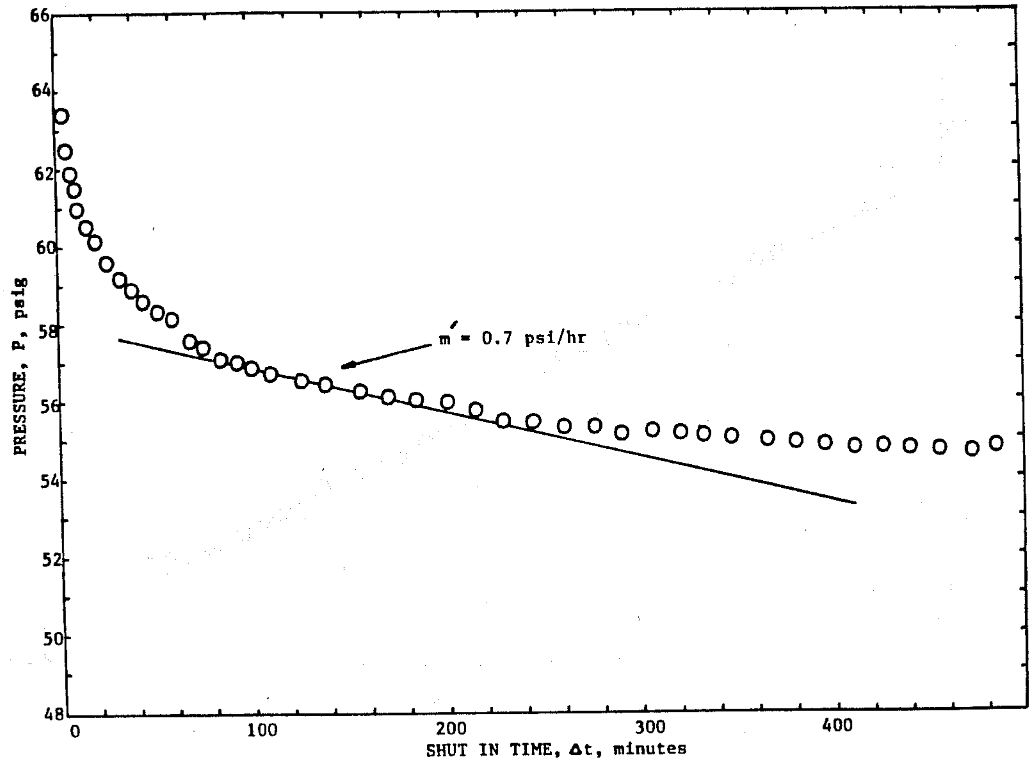


Fig. 4.38: CARTESIAN PLOT OF PRESSURE FALL-OFF DATA, WELL 208, FEB. 1982

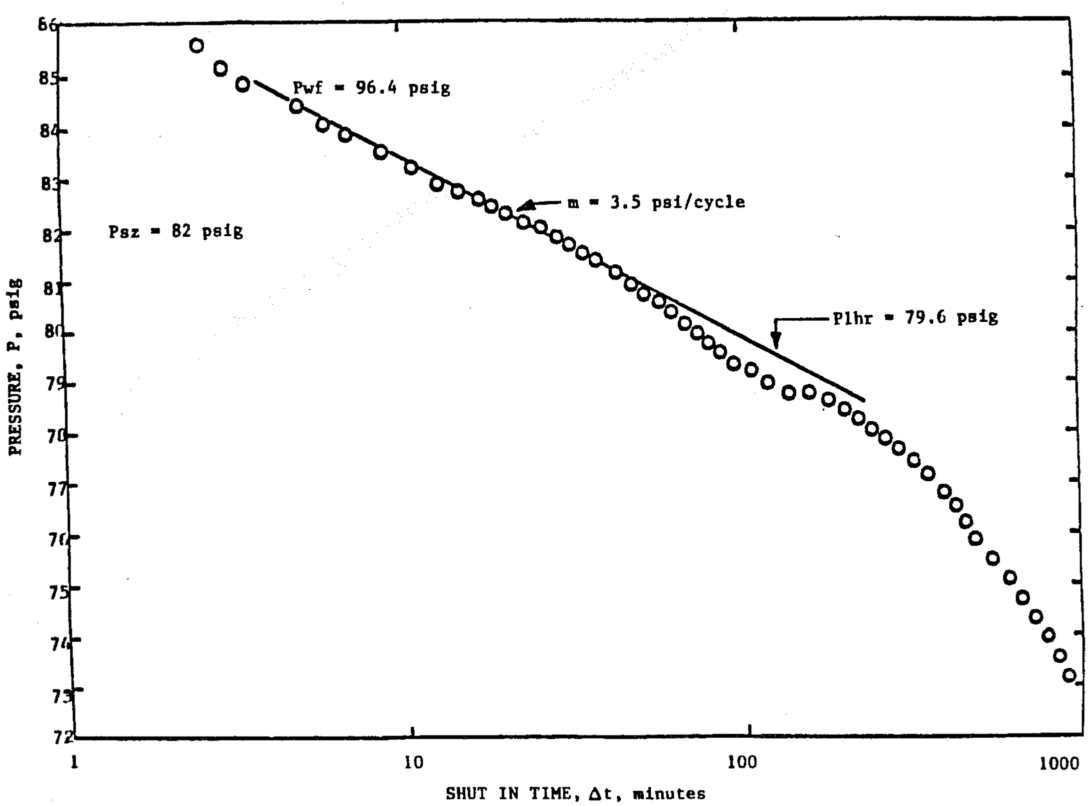


Fig. 4.39: SEMI-LOG PLOT OF PRESSURE FALL-OFF DATA, WELL 214, FEB. 1982

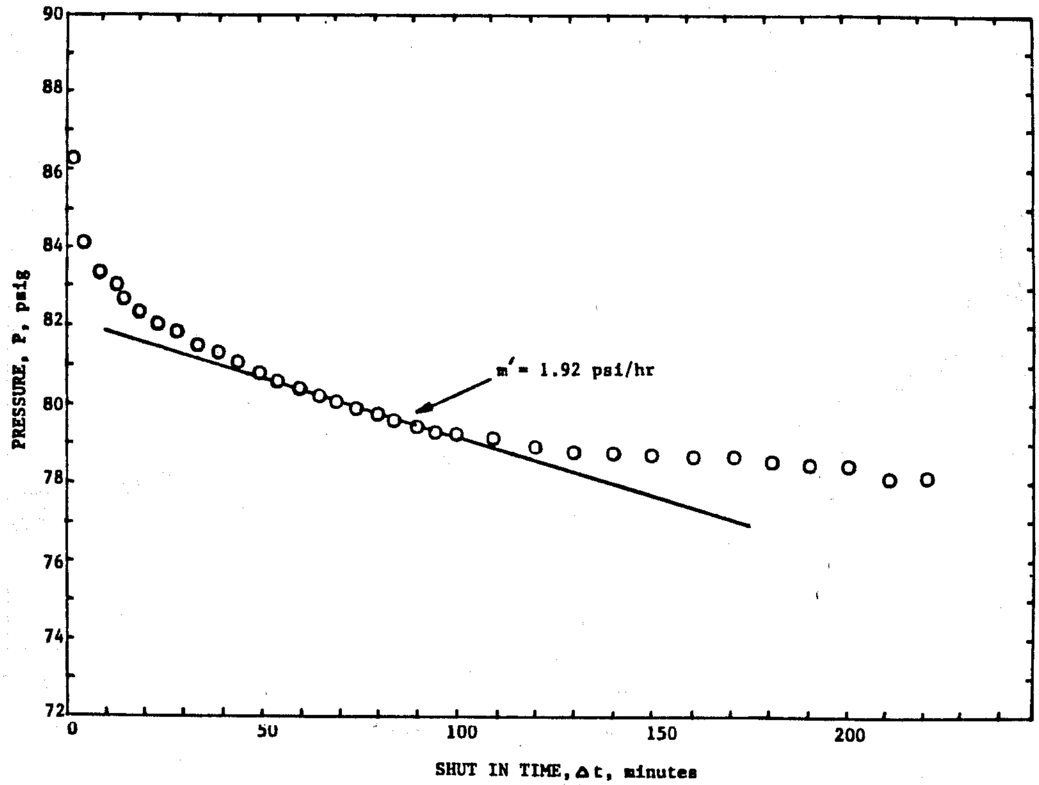


Fig. 4.40: CARTESIAN PLOT OF PRESSURE FALL-OFF DATA, WELL 214, FEB. 1982

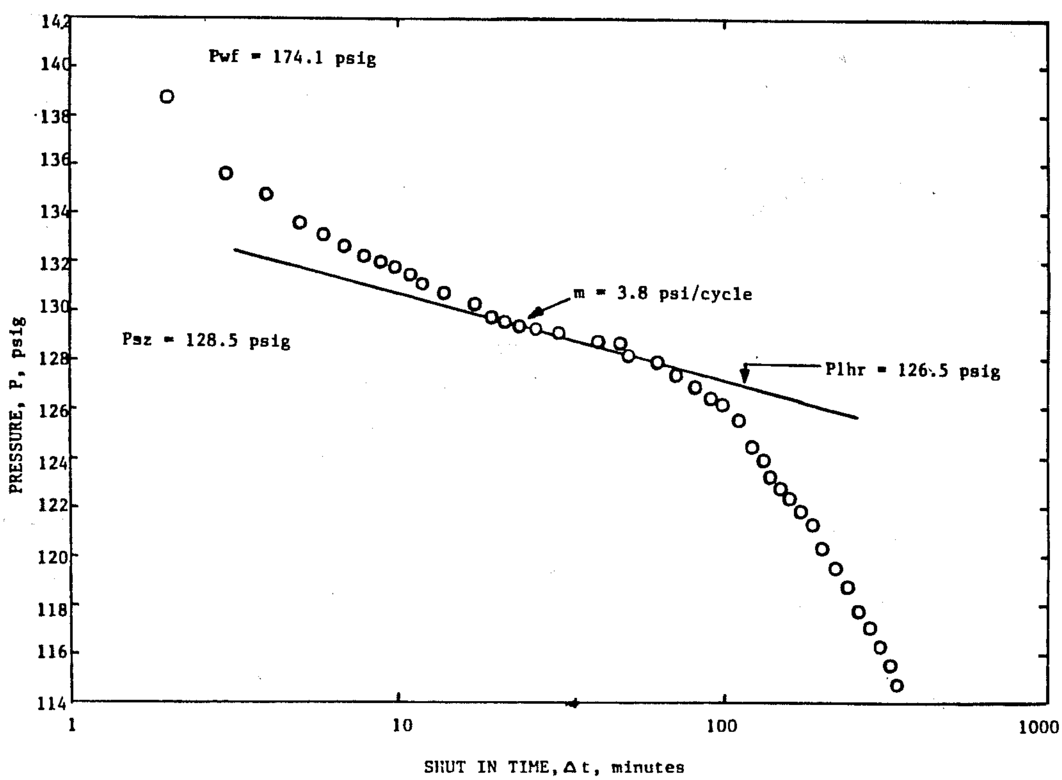


Fig. 4.41: SEMI-LOG PLOT OF PRESSURE FALL-OFF DATA, WELL 208, MAY 1982

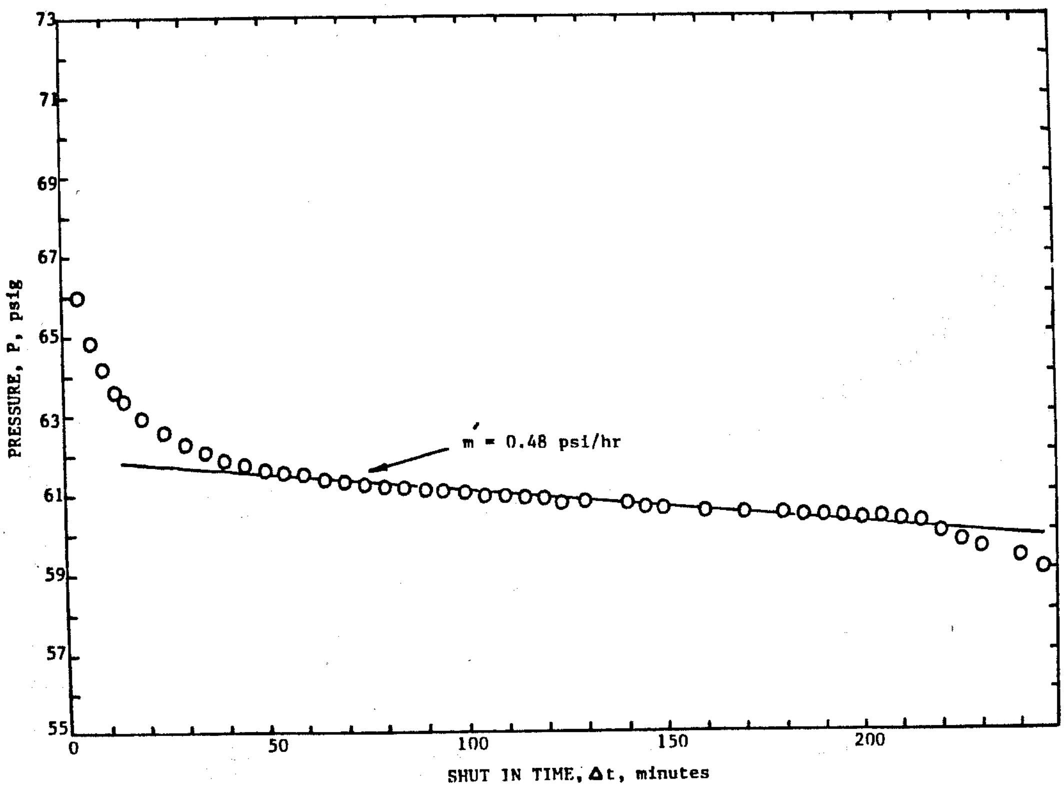


Fig. 4.42: CARTESIAN PLOT OF PRESSURE FALL-OFF DATA, WELL 208M, MAY 1982

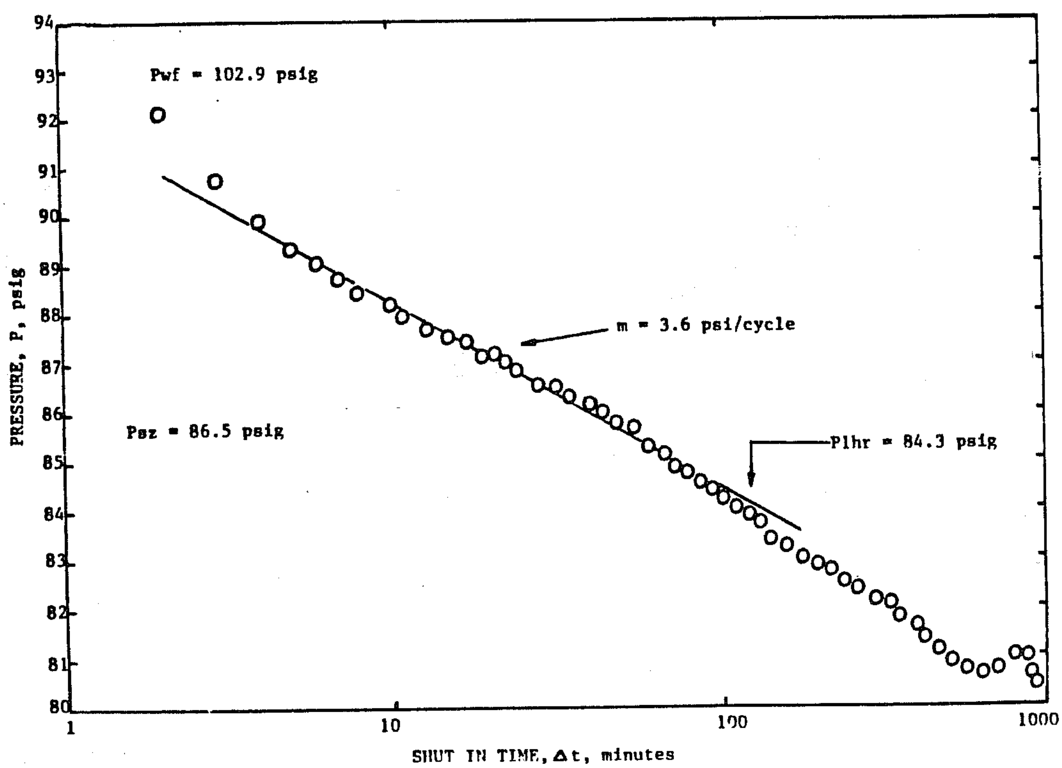


Fig. 4.43: SEMI-LOG PLOT OF PRESSURE FALL-OFF DATA, WELL 214, MAY 1982

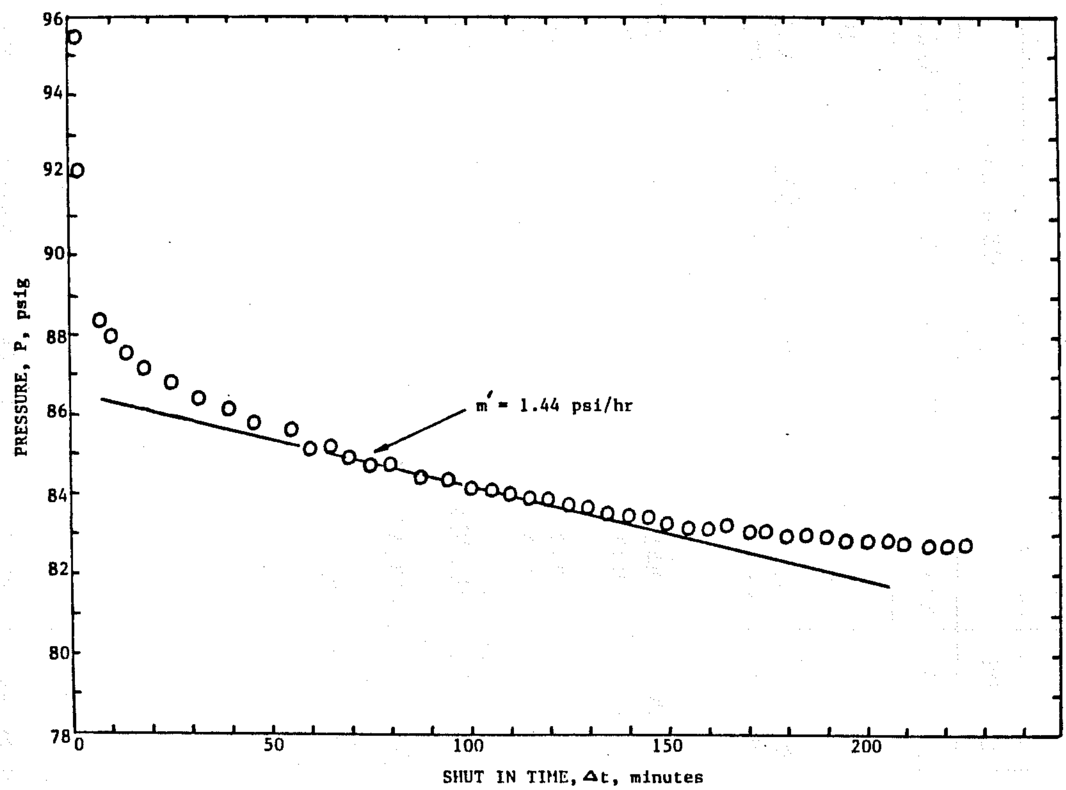


Fig. 4.44: CARTESIAN PLOT OF PRESSURE FALL-OFF DATA, WELL 214, MAY 1982

Immediately following the end of the transient periods, pseudo-steady state appeared for both wells. No transition period was observed between the end of the semi-log straight line and the pseudo-steady state straight line on a Cartesian plot of pressure versus shut-in time (Figs. 4.34, 4.36, 4.38, 4.40, 4.42 and 4.44). A transition period may indeed exist, but be too short to discern. From the slopes of the Cartesian straight lines, the pore volume in the steam swept zone was calculated using Eq. 4.16.

The calculated kh values for the two wells are shown in Table 4.5. The calculated kh for Well 214 ranged from 12,500 to 25,900 md-ft. By comparison, the kh calculated from Well 208 averaged 50,400 to 72,500 md-ft. Assuming a net pay of 60 to 77 feet, the steam vapor permeability was estimated to be on the order of 160 to 400 md for Well 214 and 650 to 1200 md for Well 208, compared with a core-derived absolute permeability of 800 to 1900 md for this formation. The low apparent permeability calculated from pressure fall-off may represent the relative permeability of the steam. The kh values for Well 208 are possibly over-estimated because steam breakthrough to the surrounding producers may have occurred at the time of the tests.

Positive skin values were also noted for these wells (+2.6 to +11.7 for Well 214 and +2.5 to +4.5 for Well 208), implying any one of several possible reasons: formation damage, incomplete penetration, effect of perforations, etc.

Table 4.5

PRESSURE FALL-OFF RESULTS FOR WELLS 208 AND 214

PARAMETER	WELL 208			WELL 214		
	10/31/81	2/10/82	5/18/82	10/30/81	2/11/82	5/17/82
Average Pressure Swept Zone, p_{sz}, psia	72	75	77	144	97	102
Compressibility of Swept Zone, psi^{-1}	0.966	0.918	0.857	0.290	0.573	0.523
kh, md-ft	72,275	50,369	50,467	12,476	25,865	22,547
Steam Zone Permeability-Thickness, kh, md-ft (60')	1,205	839	841	208	431	376
(77')	939	654	655	163	336	293
Skin, s (60')	4.3	2.5	3.9	11.6	2.6	3.1
(77')	4.4	2.6	4.0	11.7	2.7	3.2
Swept Pore Volume, ft^3	10,871	32,416	46,785	4,170	8,479	10,467
Bulk Volume Swept, ft^3	47,265	140,940	203,413	18,132	36,866	45,509
Total Heat Injected, MMM Btu	152.85	157.48	163.06	0.5637	8.462	13.752
Heat Content of Steam Zone, MMM Btu	0.36	1.10	1.11	0.17	0.31	0.39
Heat Content of Hot Water Zone, MMM Btu	0.16	0.48	0.48	0.09	0.15	0.19
Heat in Steam Zone, %	0.24	1.21	0.69	30.26	3.66	2.82
Heat in Water Zone, %	0.10	0.30	0.30	16.3	1.74	1.36
Heat Lost, %	99.66	98.49	99.02	53.44	94.60	95.82

For Well 214, which has been on steam injection since October 1981, the swept volumes appear reasonable from a volumetric sweep viewpoint. After seven months of continuous steam injection, less than 0.8% of the available reservoir volume is estimated to have been swept by steam. Bulk volume swept for the three separate test dates is shown in Fig. 4.45.

By comparison, 3.5% of the available reservoir volume surrounding Well 208 is estimated to have been swept by steam after 3.5 years of steam injection. This value is over-estimated because steam breakthrough to the surrounding wells has occurred. To properly account for steam breakthrough, the net steam injection rate (injection rate minus production rate from the pattern) should be used; however, net rates could not be used, because steam production at the producers is not recorded. Disruption of the pseudo-steady state pressure decline due to a rising wellbore liquid level makes selection of the Cartesian straight line somewhat difficult for the October 1981 test. Selection of a line with too steep a slope causes the pore volume swept to be under-estimated. Figure 4.45 shows the swept volumes for the three different tests. Figure 4.45 does indicate the growth of steam-swept volume with time, even though the calculated values for steam-swept zones may not be accurate.

The estimated heat content for the steam and hot water zones surrounding Well 214 were only a small fraction of the heat injected--5.4% and 4.2% for the

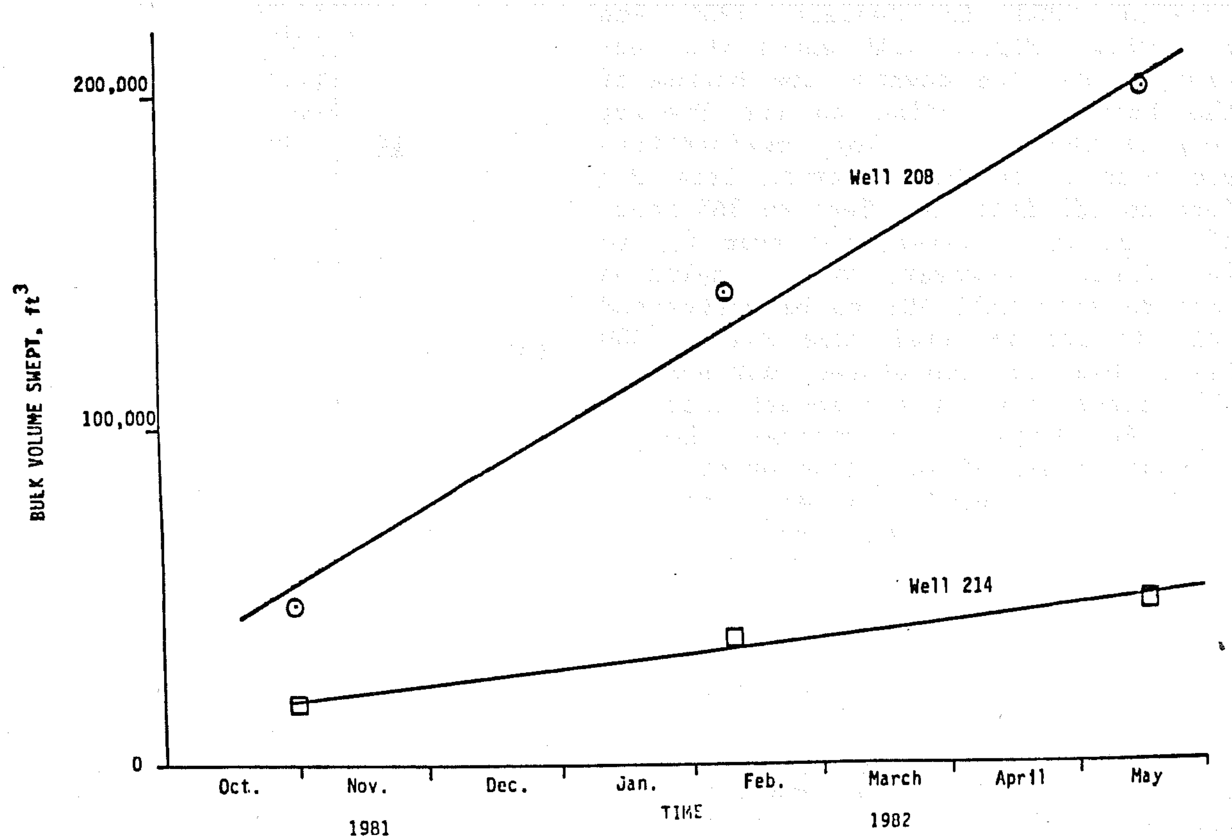


Fig. 4.45: BULK VOLUME SWEPT AS CALCULATED FROM PRESSURE FALL-OFF TEST VERSUS TIME

February 1982 and May 1982 tests, respectively. As a result, low thermal efficiencies were indicated with 95% to 96% of the heat injected being lost to the overburden, underburden and produced fluids. Since no steam breakthrough had been noted, most of the heat loss probably occurred to the overburden and underburden. Only 53% heat loss was calculated for the October 1981 test. Such a sharp contrast is probably due to the fact that Well 214 had only undergone ten days of continuous steam injection at the time of the test. For Well 208, even lower thermal efficiencies were obtained on all dates. Approximately 98% to 100% of the heat was lost. This would be expected if steam breakthrough to the surrounding producers had occurred. As noted by Walsh et al. [1981], further investigation into the estimation of the heat content ahead of the swept region is warranted so that accurate assessment of the efficiency of thermal recovery projects can be made. Williams [1982], who recently applied this same analysis technique to Getty Oil Co. steamflood patterns located in the Kern River field, has also found that the steam-swept zone and heat loss calculated by this method appear to be over-estimated.

4.6 ANALYSIS OF INJECTIVITY TEST DATA

Before interpretation of the injectivity profiles was attempted, the Casing Profile Caliper log run in injector 208 in January 1981 was reviewed. Figure 4.46 shows the section of the log towards the bottom of the hole. According to the Dia-Log Company who ran the log, perforations are present in the interval from 344 feet to 352 feet, 363 feet to 365 feet, 372 feet to 387 feet, and from 425 to 440 feet. However, well completion records show Well 208 to be perforated only in the interval from 344 to 389 feet. Dia-Log also stated that some of the perforations in the lowest interval might be plugged. In general, though, no major areas of wall loss or significantly adverse conditions were noted by the log trace, and the casing in the logged interval (surface to depth of 467 feet) appeared to be in good condition.

An attempt was made to analyze the injectivity profiles for Well 208 by determining the percentage of fluid flow--both gas and water--into various layers of the formation. Analysis is presented in Figs. 4.47 through 4.54 and Tables 4.6 through 4.11. Separate tables are shown for gas- and water-phase tracer profiles for each different test date.

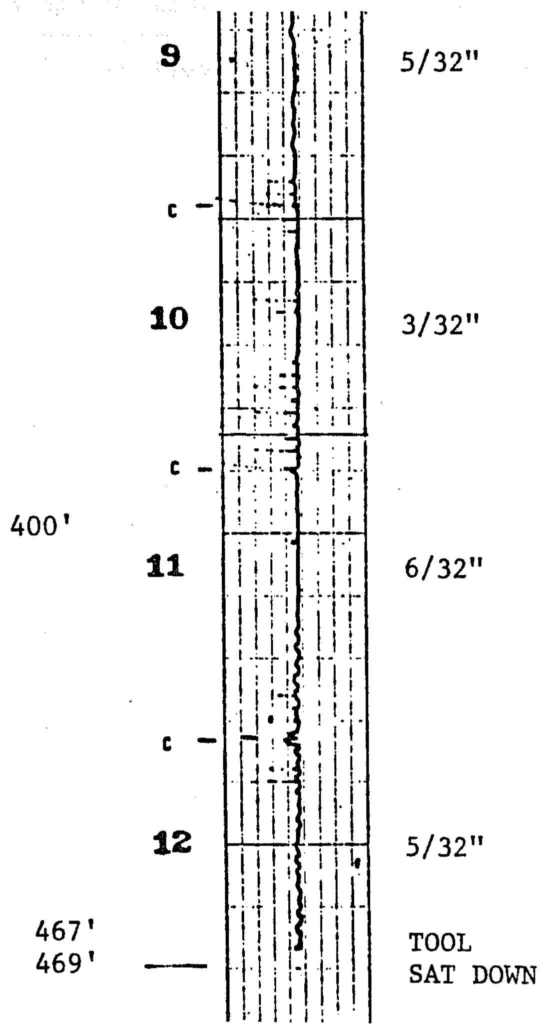


Fig. 4.46: CASING PROFILE CALIPER FOR WELL 208

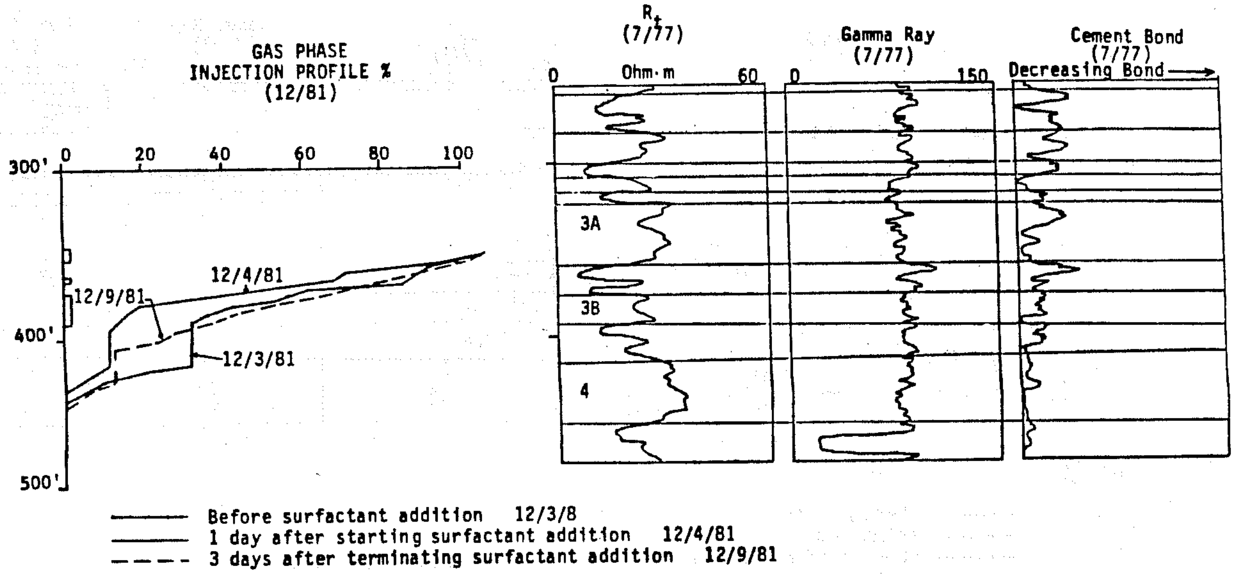


Fig. 4.47: INJECTIVITY PROFILES BASED ON GAS-PHASE TRACER IN WELL 208, DECEMBER 1981

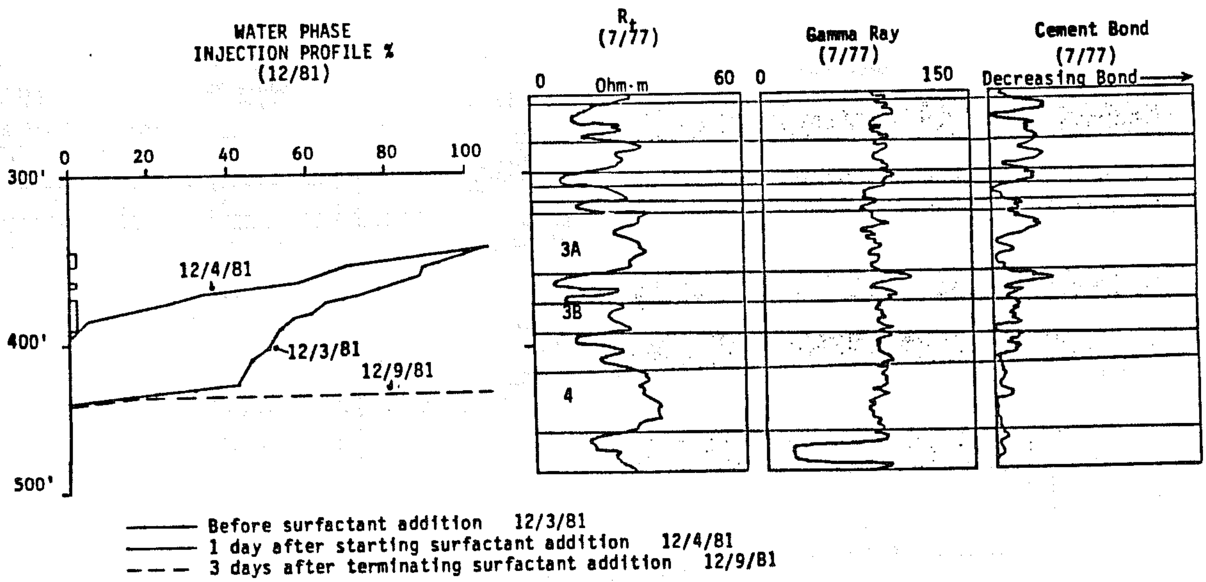


Fig. 4.48: INJECTIVITY PROFILES BASED ON WATER-PHASE TRACER IN WELL 208, DECEMBER 1981

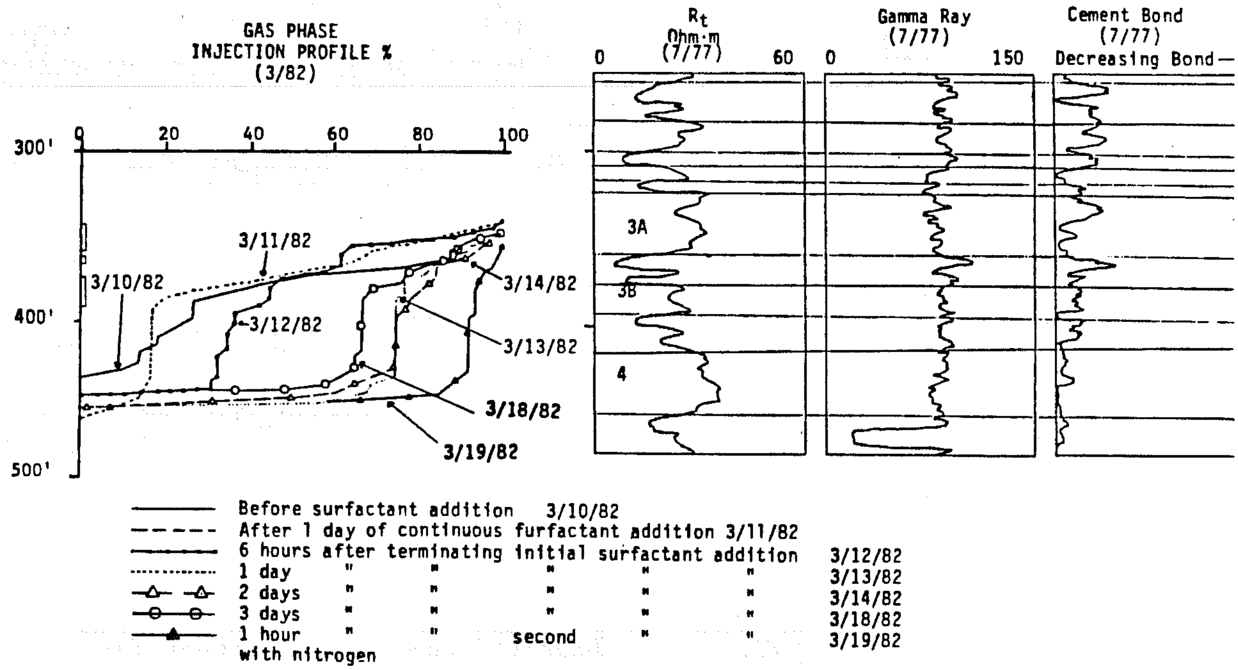


Fig. 4.49: INJECTIVITY PROFILES BASED ON GAS-PHASE TRACER IN WELL 208, MARCH 1982

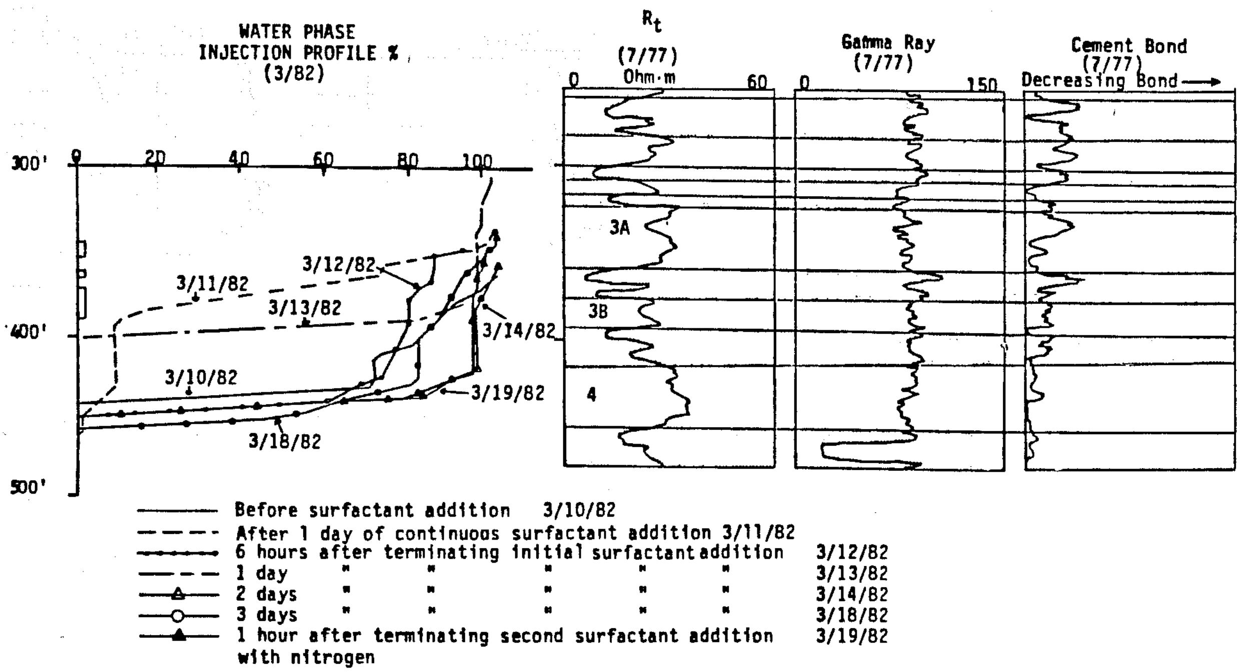


Fig. 4.50: INJECTIVITY PROFILES BASED ON WATER-PHASE TRACER IN WELL 208, MARCH 1982

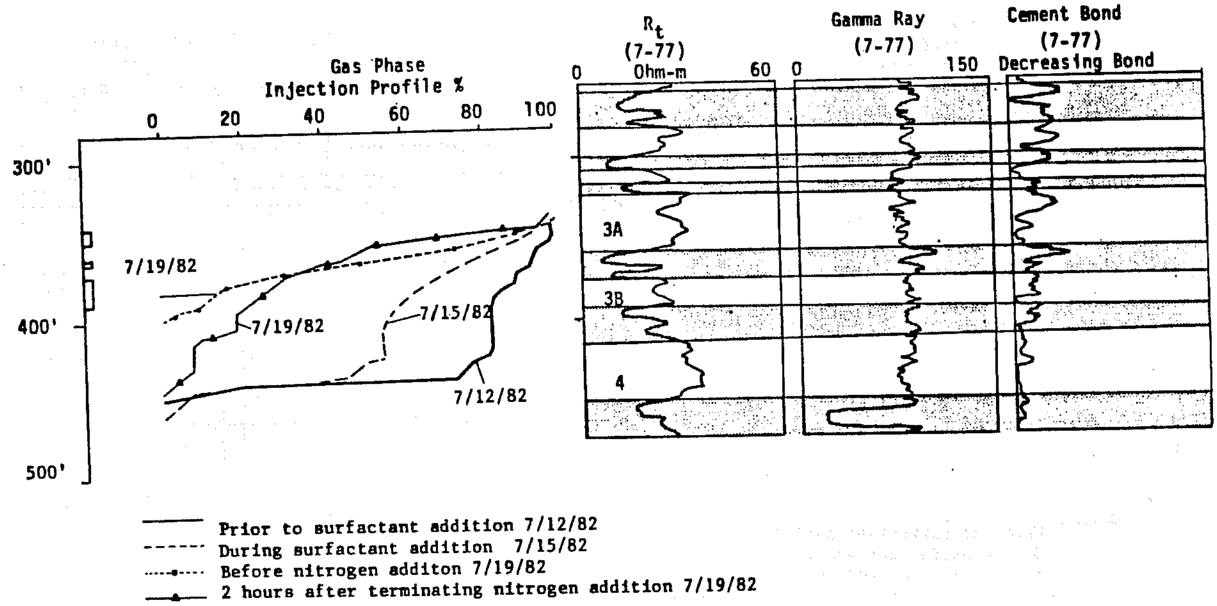


Fig. 4.51: INJECTIVITY PROFILES BASED ON GAS-PHASE TRACER IN WELL 208, JULY 12 TO 19, 1982

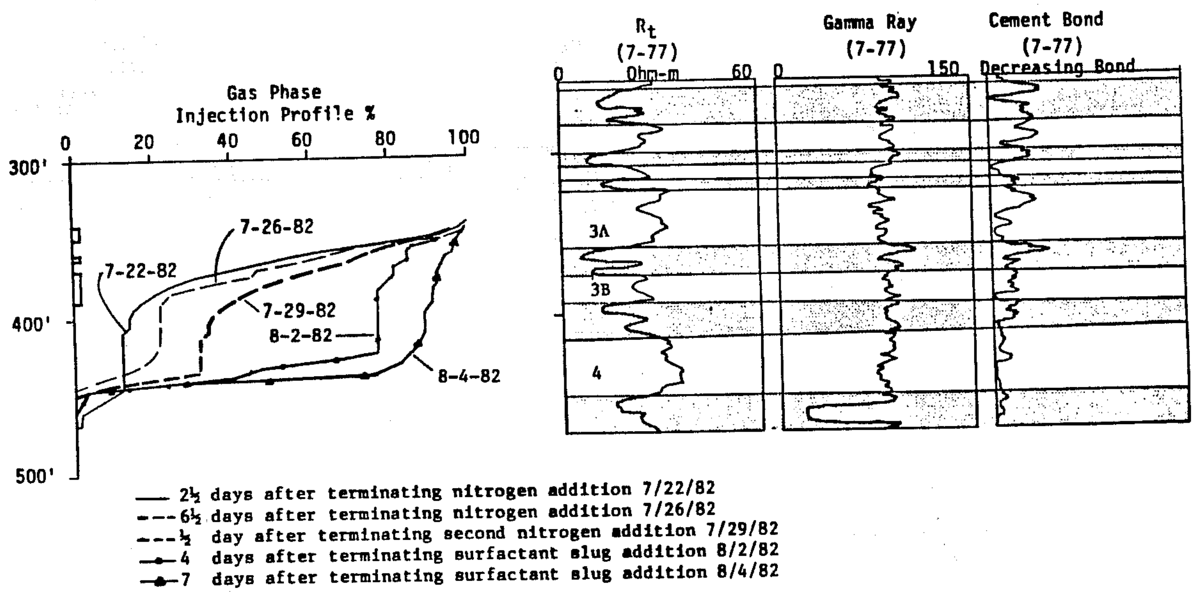


Fig. 4.52: INJECTIVITY PROFILES BASED ON GAS-PHASE TRACER IN WELL 208, JULY 22 TO AUGUST 4, 1982

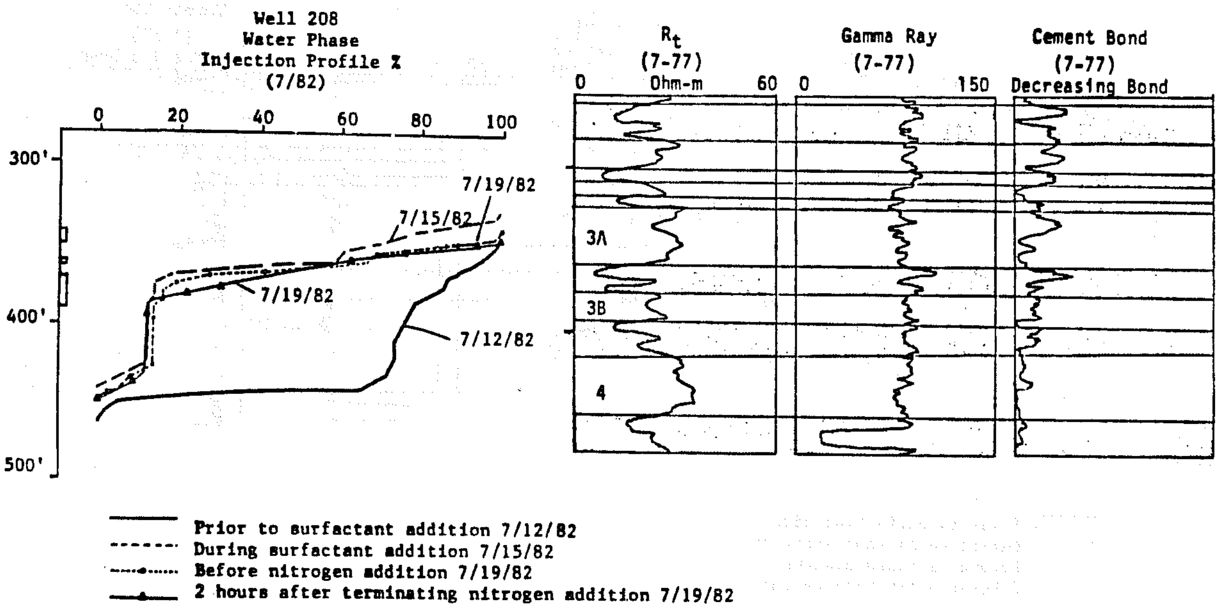


Fig. 4.53: INJECTIVITY PROFILES BASED ON GAS-PHASE TRACER IN WELL 208, JULY 12 TO 19, 1982

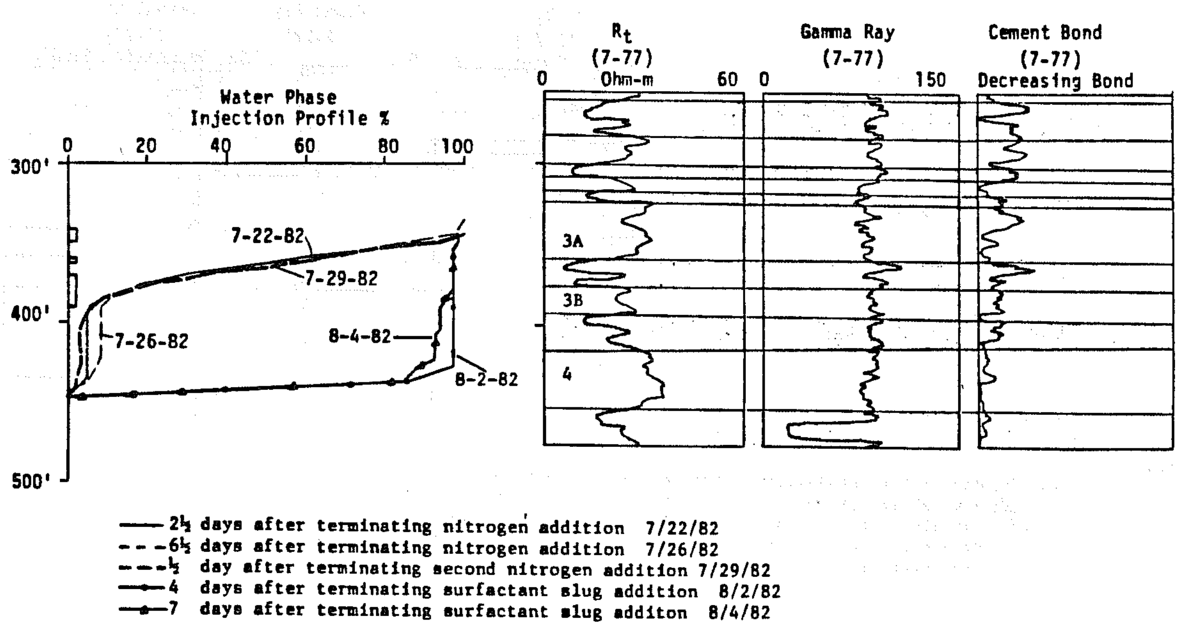


Fig. 4.54: INJECTIVITY PROFILES BASED ON WATER PHASE-TRACER IN WELL 208, JULY 22 TO AUGUST 4, 1982

Table 4.6

ANALYSIS OF INJECTIVITY PROFILE, GAS PHASE, DECEMBER 1981

DATE	PERCENTAGE OF FLOW ENTERING Slice 3A	Slice 3B	Slice 4	Below Slice 4	REMARKS
12/3	15	55	30	0	Prior to surfactant injection. Steam flow behind pipe.
12/4	24	66	10	0	After 1 day continuous surfactant injection of 15% active at 0.5 gpm. Reduced flow behind pipe?
12/9	8	66	26	0	3 days after terminating surfactant injection. 2300 gallons total added.

Table 4.7

ANALYSIS OF INJECTIVITY PROFILE, WATER PHASE, DECEMBER 1981

DATE	PERCENTAGE OF FLOW ENTERING Slice 3A	Slice 3B	Slice 4	Below Slice 4	REMARKS
12/3	17	33	50	0	Prior to surfactant injection. Appreciable water flow into slice 4.
12/4	42	56	2	0	After 1 day continuous surfactant injection of 15% active at 0.5 gpm. Foam diverting flow into perforated slices 3A and 3B?
12/9	0	0	100	0	3 days after terminating surfactant injection. 2300 gallons total added. Foaming entirely blocking perforated slices 3A and 3B.

Table 4.8

ANALYSIS OF INJECTIVITY PROFILE, GAS PHASE, MARCH 1982

DATE	PERCENTAGE OF FLOW ENTERING Slice 3A	Slice 3B	Slice 4	Below Slice 4	REMARKS
3/10	12	61	27	0	Prior to surfactant injection. Steam flow behind pipe.
3/11	31	51	14	4	After 1 day continuous surfactant injection of 15% active at 0.75 gpm. Flow behind pipe diminished?
3/12	39	22	39	0	6 hours after terminating surfactant injection. 1380 gallons total injected.
3/13	12	13	75	0	1 day after terminating surfactant injection.
3/14	7	16	77	0	2 days after terminating surfactant injection.
3/18	11	22	67	0	1 hour after terminating second surfactant injection. 1120 gallons surfactant and 36,000 SCF nitrogen injected.
3/19	0	7	93	0	1 day after terminating second surfactant injection. Foam in presence of nitrogen appears to have totally blocked flow in steam-swept slice 3A and reduced flow substantially into 3B.

Table 4.9

ANALYSIS OF INJECTIVITY PROFILE, WATER PHASE, MARCH 1982

	PERCENTAGE OF FLOW ENTERING				
DATE	Slice 3A	Slice 3B	Slice 4	Below Slice 4	REMARKS
3/10	0	14	86	0	Prior to surfactant injection. Steam flow behind pipe.
3/11	27	63	9	1	After 1 day continuous surfactant injection of 15% active at 0.75 gpm. Flow behind pipe diminished?
3/12	15	5	80	0	6 hours after terminating surfactant injection. 1380 gallons total injected.
3/13	4	32	64	0	1 day after terminating surfactant injection.
3/14	0	4	96	0	2 days after terminating surfactant injection.
3/18	6	9	64	21	1 hour after terminating second surfactant injection. 1120 gallons surfactant and 36,000 SCF nitrogen injected.
3/19	3	2	95	0	1 day after terminating second surfactant injection. Foam in presence of nitrogen appears to be increasing blockage of perforated slices 3A and 3B.

Table 4.10

ANALYSIS OF INJECTIVITY PROFILE, GAS PHASE, JULY 1982

DATE	PERCENTAGE OF FLOW ENTERING Slice 3A	Slice 3B	Slice 4	Below Slice 4	REMARKS
7/12	7	11	82	0	Prior to surfactant injection. Appreciable gas flow into slice 4.
7/15	20	22	55	3	After 1 day continuous surfactant injection at 0.25 gpm. Foam diverting steam flow to slices 3A and 3B.
7/19	40	56	4	0	Before nitrogen addition. Surfactant flow at 1.25 gpm.
7/19	54	27	19	0	2 hours after terminating nitrogen injection at 12,500 SCFH. 100,000 SCF added.
7/22	46	39	11	4	2.5 days after terminating nitrogen injection.
7/26	44	51	5	0	6.5 days after terminating nitrogen injection.
7/29	28	36	36	0	0.5 day after terminating second nitrogen injection. 200,000 SCF added. Steam flow to slice 4 increasing.
8/2	13	6	80	1	4 days after terminating surfactant slug addition. 21,600 gallons total added. Appreciable flow to slice 4.
8/4	3	6	87	4	7 days after terminating surfactant slug addition. No significant change in flow to slice 4.

Table 4.11

ANALYSIS OF INJECTIVITY PROFILE, WATER PHASE, JULY 1982

DATE	PERCENTAGE OF FLOW ENTERING Slice 3A	Slice 3B	Slice 4	Below Slice 4	REMARKS
7/12	5	17	75	3	Prior to surfactant injection. Significant water flow into slice 4.
7/15	41	47	12	0	After 1 day continuous surfactant injection at 0.25 gpm. Foam diverting flow into slices 3A and 3B.
7/19	33	54	13	0	Before nitrogen addition. Surfactant flow at 1.25 gpm.
7/19	38	50	12	0	2 hours after terminating nitrogen injection at 12,500 SCFH. 100,000 SCF added.
7/22	51	43	6	0	2.5 days after terminating nitrogen injection.
7/26	44	51	5	0	6.5 days after terminating nitrogen injection.
7/29	42	50	8	0	0.5 day after terminating second nitrogen injection. 200,000 SCF added.
8/2	1	0	99	0	4 days after terminating surfactant slug addition. 21,600 gallons total added. Flow being diverted into slice 4.
8/4	1	4	94	1	7 days after terminating surfactant slug addition.

The December 1982 injectivity profiles (Figs. 4.47 and 4.48) show that an appreciable fraction of total steam and water flow into the formation through the perforations is located in slice 4. It appears that a portion of the steam entering these lower perforations may be flowing between the casing and cement. Surfactant injection appears to initially cause water flow to be diverted into slices 3A and 3B (Table 4.7). However, shortly after beginning surfactant injection and for a time following termination of surfactant injection, water is blocked from entering slices 3A and 3B, presumably by continued foam generation deeper in the formation.

Steam flow into slice 4 also appears to decrease initially with surfactant flow, followed by an increase of flow to slice 4 after surfactant addition stopped (Fig. 4.55 and Table 4.6). Conclusions for the December 1981 test are tenuous since the Suntech IV surfactant injected was different than the Suntech IV previously tested in the laboratory.

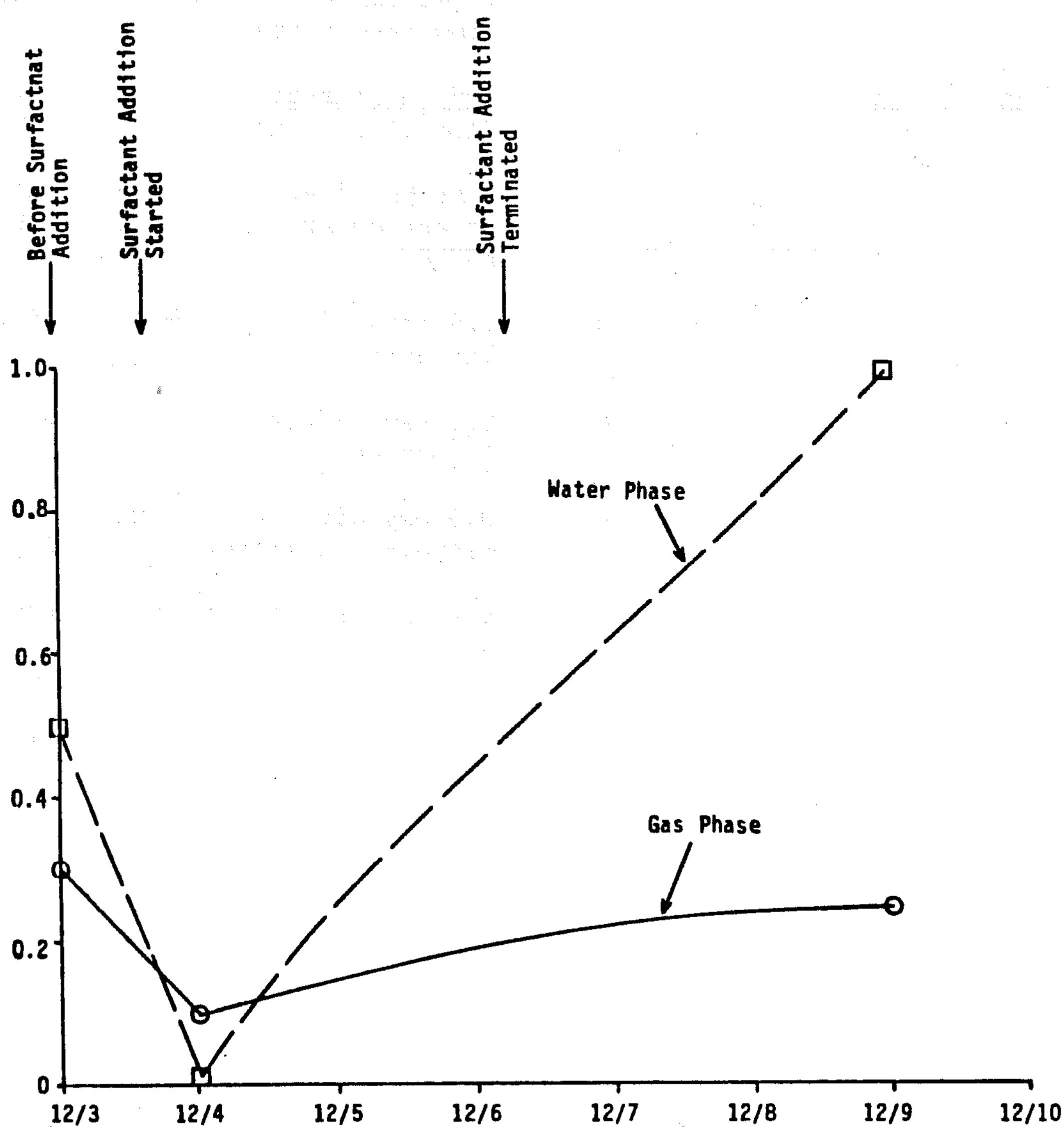


Fig. 4.55: FRACTION OF INJECTED STEAM ENTERING SLICE 4 OR BELOW VERSUS TIME, DECEMBER 1981

During the March 1982 injectivity test (Figs. 4.49 and 4.50), surfactant appears to have reduced both the fractional flow of gas and water entering slice 4, followed by a steady increase in flow (Fig. 4.56 and Tables 4.8 and 4.9). Nitrogen injection appears to further block entry of the gas phase into the perforations in slices 3A and 3B.

The July 1982 injectivity test appears to show that both the gas- and water-phase profiles (Figs. 4.51 through 4.54) prior to surfactant addition are very similar to the profiles obtained on March 19, 1982 (Figs. 4.47 and 4.48). Initial surfactant addition appears again to have reduced both gas and liquid flow below slice 4 and increased fractional flow into slices 3A and 3B (Tables 4.10 and 4.11). The effect appears to be more pronounced for the water phase. No systematic trend due to nitrogen injection is discernable (Fig. 4.57).

From these tests, it appears that surfactant injection first decreases the fractional flow of gas and steam into the perforations in slice 4 and then increases flow after injection has been terminated and in-situ generation of foam continues. Nitrogen seems to enhance this increase, which is possible if nitrogen addition causes more effective foam formation and therefore blockage of the upper perforated zones.

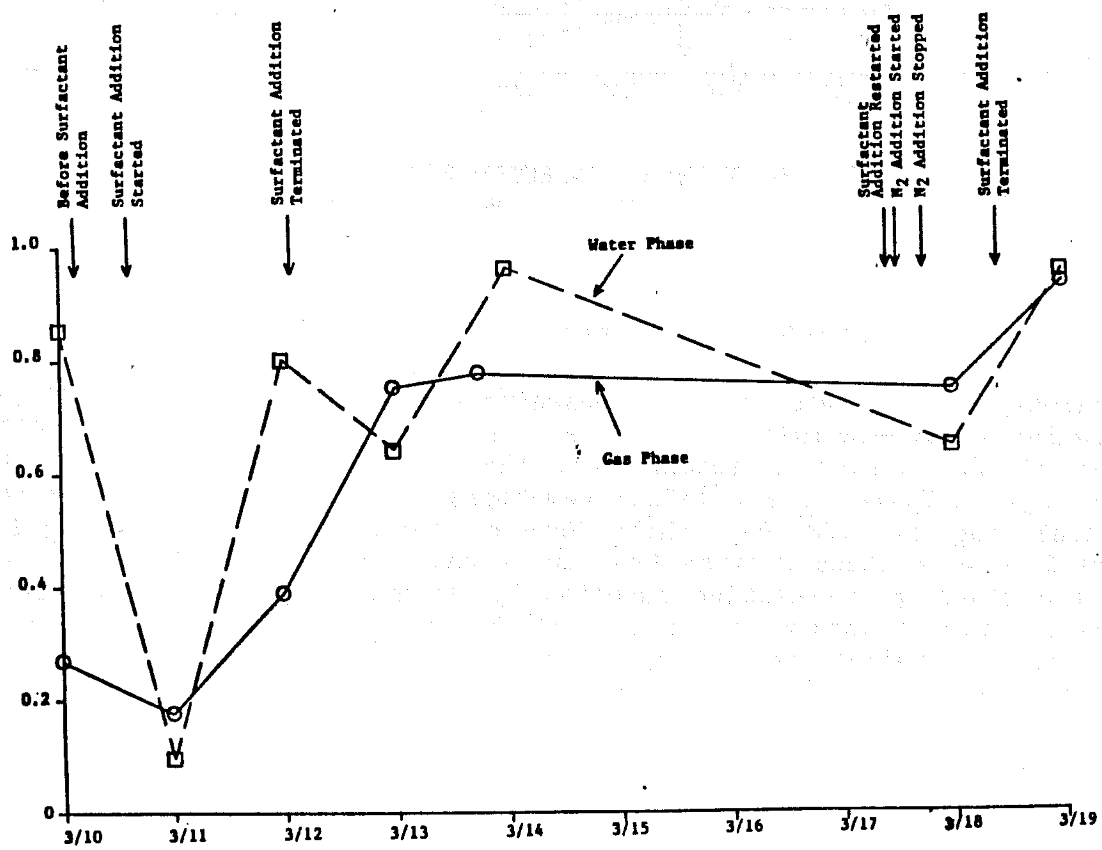


Fig. 4.56: FRACTION OF INJECTED STEAM ENTERING SLICE 4 OR BELOW VERSUS TIME, MARCH 1982

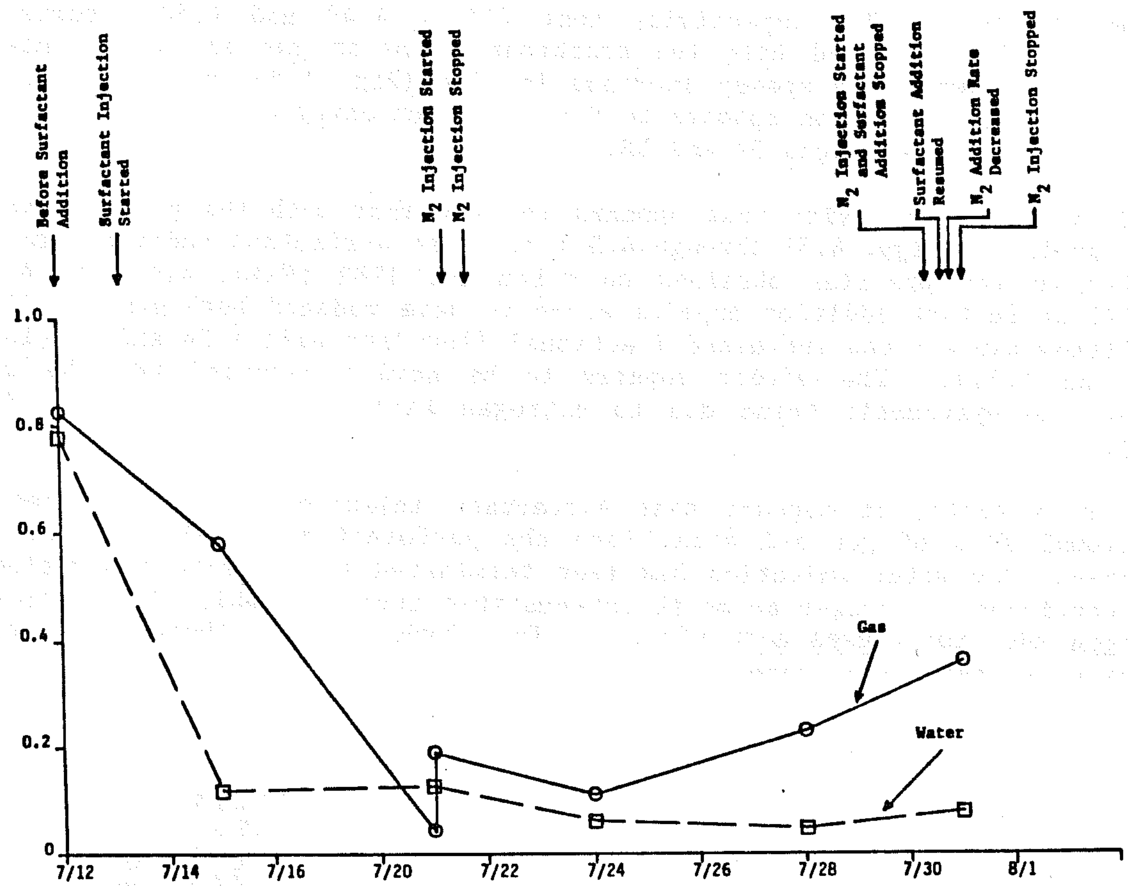


Fig. 4.57: FRACTION OF INJECTED STEAM ENTERING SLICE 4 OR BELOW VERSUS TIME, JULY 1982

4.7 ANALYSIS OF CARBON/OXYGEN LOG DATA

Carbon/Oxygen logs are run in cased-hole wells to monitor hydrocarbon saturation in low-salinity reservoirs. At SUPRI, O'Brien et al. [1982] and Horner [1982a] conducted research on the application of the Carbon/Oxygen (C/O) log. O'Brien et al. [1982] developed a graphical crossplot technique for analyzing the C/O log, while Horner [1982a] compared C/O log-derived saturations with those derived from cores and open-hole logs. Horner showed that the standard correlation supplied by Dresser-Atlas is not accurate for the SUPRI pilot. Horner also concluded that individual correlations could be developed on a well-by-well basis by using the earliest Carbon/Oxygen log run and open-hole log measurements. He calibrated the Carbon/Oxygen log in both Wells 208M and 214M with the EPT-predicted value for oil saturation-porosity product. The equation Horner obtained for Well 214M was:

$$\phi S_o = 0.674 \ C/O + 0.472 \ Si/Ca - 1.507 \qquad (4.19)$$

For Well 208M, the equation was:

$$\phi S_o = 0.484\ C/O + 0.223\ Si/Ca - 0.941 \tag{4.20}$$

In these equations, the C/O and Si/Ca ratios are derived from the Dresser-Atlas conventional log rather than from the processed spectra.

In this study, the Carbon/Oxygen log to date has been used as a qualitative tool for monitoring change in hydrocarbon saturation. The C/O ratio, Si/Ca ratio and Si/Ca ratio inverse for Wells 208M and 214M are shown in Figs. 4.58 and 4.59, respectively. Profiles from the Carbon/Oxygen logs run in August 1981, February 1982 and May 1982 are shown for each of the ratios. Examination of these profiles shows that while both the C/O and Si/Ca ratios change with time, the Si/Ca ratio exhibits a more pronounced change. In addition, it is perhaps not necessary to run Carbon/Oxygen logs at three-month intervals to monitor oil changes in the reservoir. Because the percentage of oil-in-place produced in three months is small, Carbon/Oxygen logs can be run at six-to-nine month intervals and still yield satisfactory results.

4.8 ANALYSIS OF INJECTION RESPONSE

Figures 4.60 through 4.64 show the wellhead pressure response during injection of the first slug of surfactant. Detailed analysis of this data is currently underway.

During heavy oil recovery by steam drive, oil/water emulsification may occur. To break these emulsions, chemicals are frequently added to the produced oil and water entering the separators (refineries will not accept oil with a high water-percentage as feed stock, and excessive oil in the water re-used as steam-generator boiler feed causes operational problems).

Examination of produced-fluid samples from the producers in the control and test patterns showed some emulsion problems. One week after injection of the first slug of Suntech IV began in Well 120, double the amount of emulsion breaker was needed on a laboratory scale to effectively separate the oil and water produced. In the field, however, at no time during injection was emulsification severe enough to warrant diverting the flow stream from Well 120 to a different separator for additional chemical treatment. Emulsion breaker requirements for Well 120 decreased rapidly following completion of the slug injection.

During the last two days of surfactant injection and for two to three days after injection of the first surfactant slug had been completed, 20% to 25% more emulsion breaker was needed to treat produced fluids from Wells 113B and 114. It should be noted that the total usage of emulsion breaker in the field during injection of the first Suntech IV surfactant slug, however, did not increase noticeably. No surfactant was ever detected at the producers.

Preliminary analysis of the data indicates an increase in the oil production rate for the test pattern and a decrease in the wellhead temperature (see Fig. 4.65) at the production wells. Therefore, the injection of the first slug of Suntech IV has been able to reduce steam channeling and increase oil recovery.

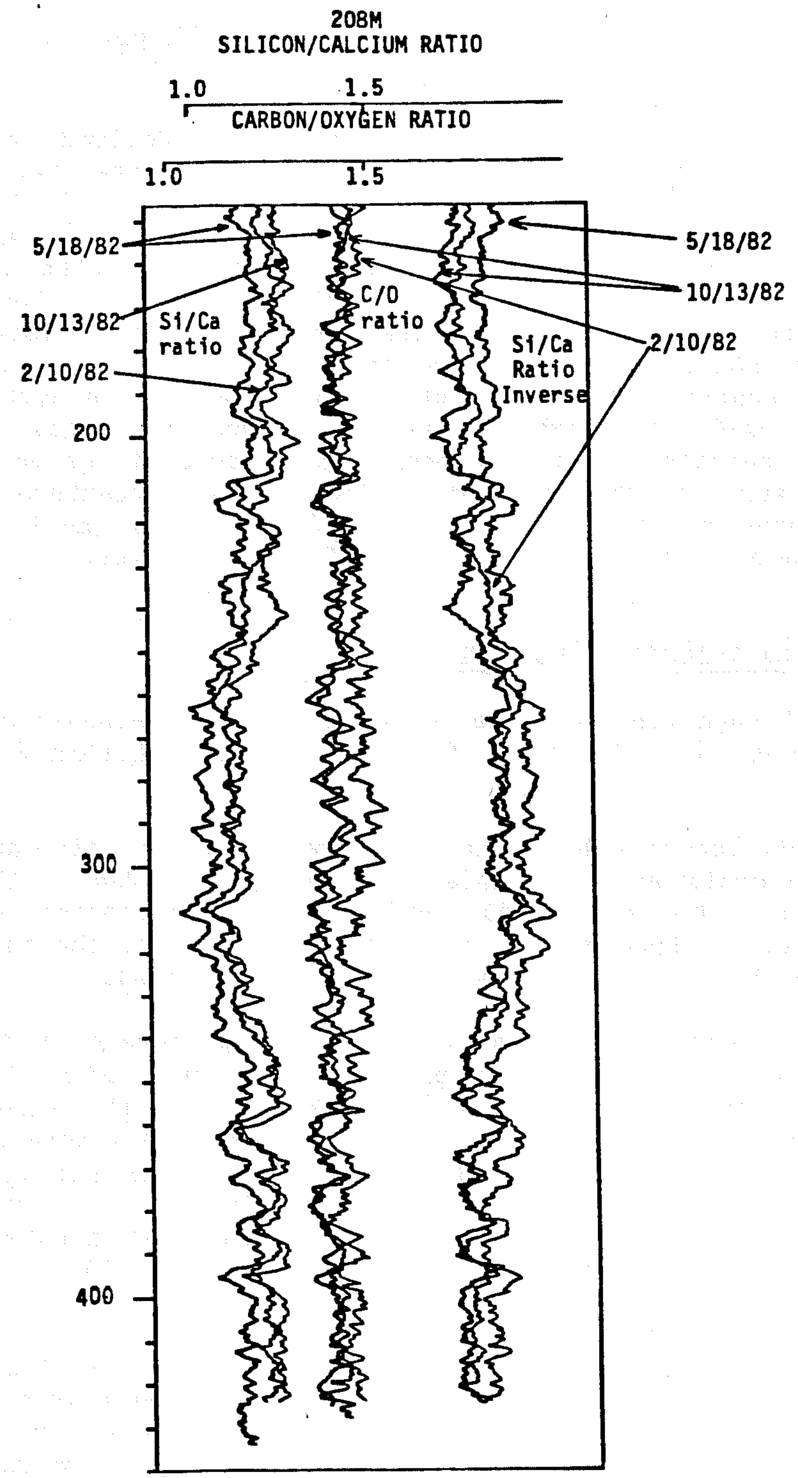


Fig. 4.58: COMPARISON OF CARBON/OXYGEN AND SILICON/CALCIUM PROFILES AS A FUNCTION OF TIME IN WELL 208M

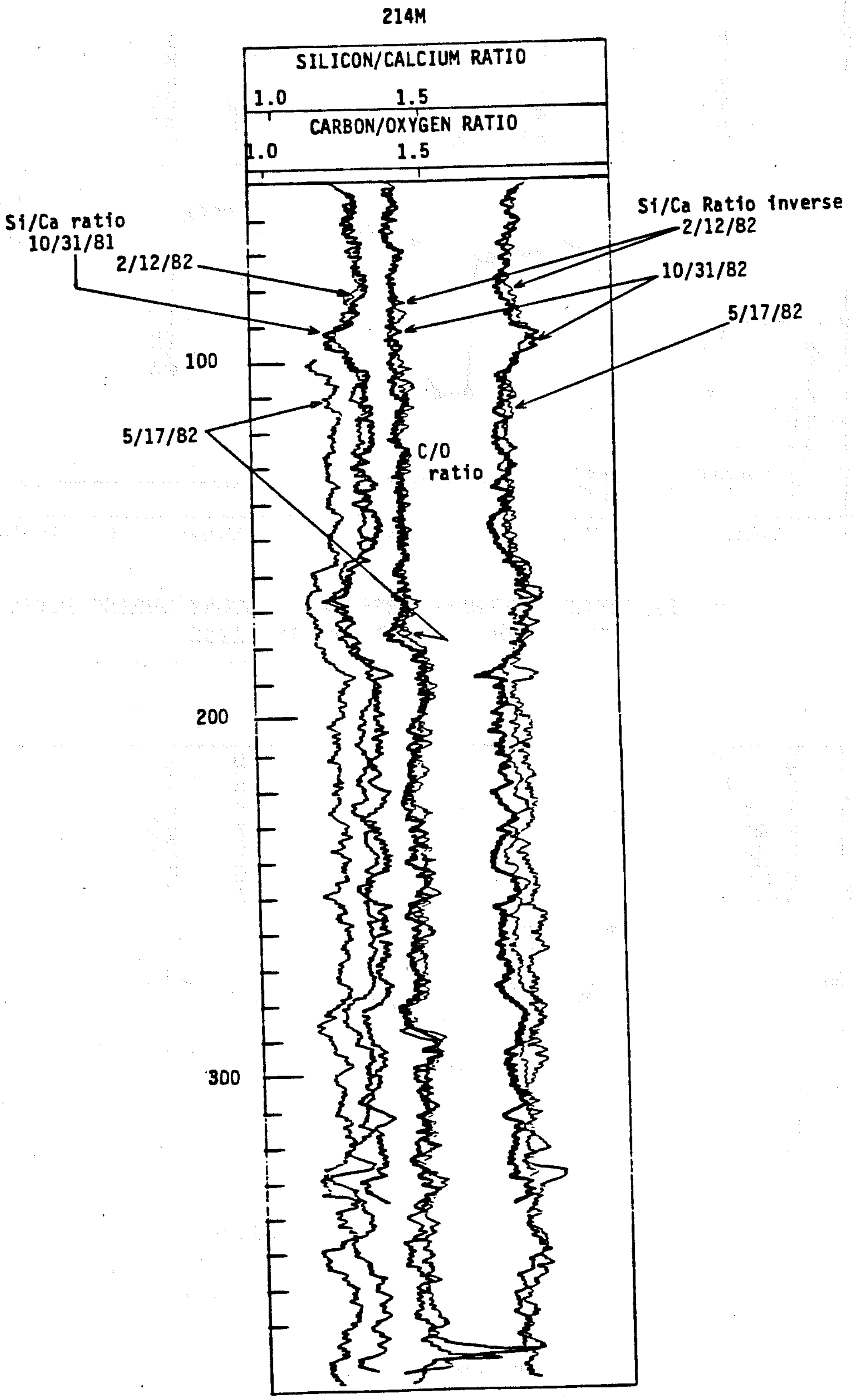


Fig. 4.59: COMPARISON OF CARBON/OXYGEN AND SILICON/CALCIUM PROFILES AS A FUNCTION OF TIME IN WELL 214M

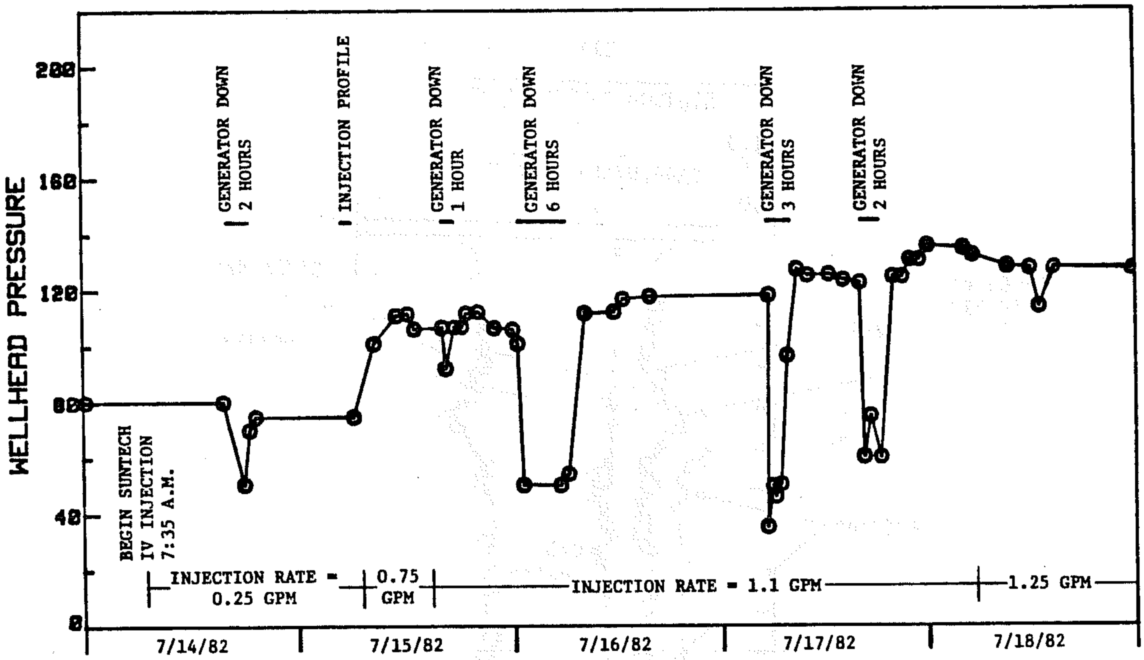


Fig. 4.60: INJECTION WELLHEAD PRESSURE HISTORY DURING FIRST SLUG INJECTION, JULY 14 TO 18, 1982

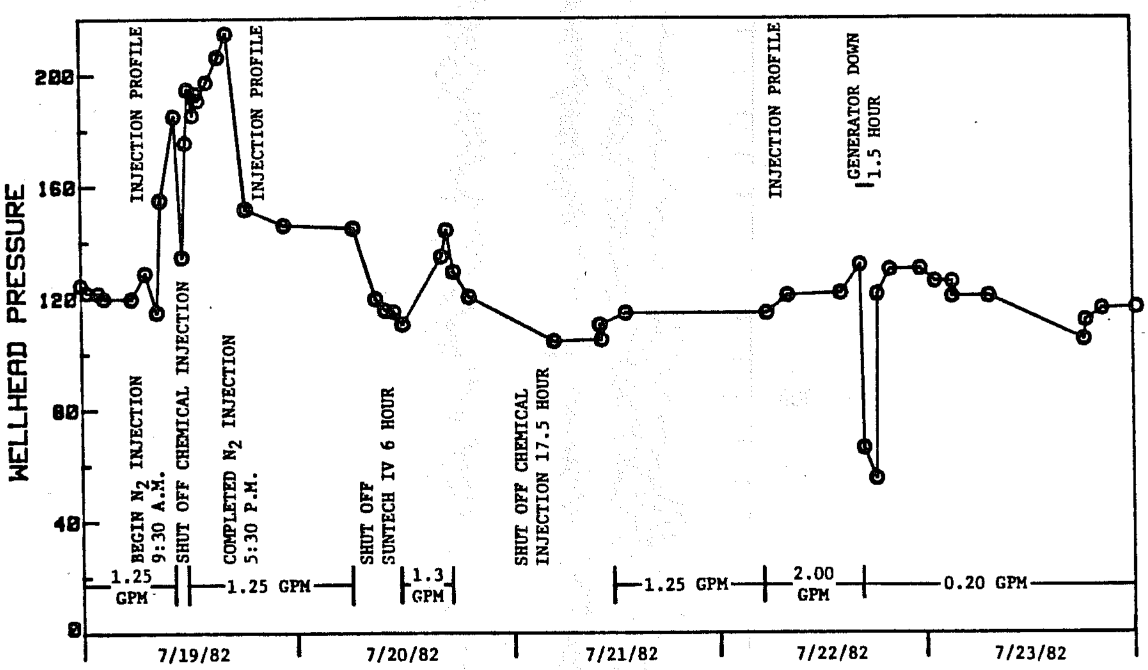


Fig. 4.61: INJECTION WELLHEAD PRESSURE HISTORY DURING FIRST SLUG INJECTION, JULY 19 TO 23, 1982

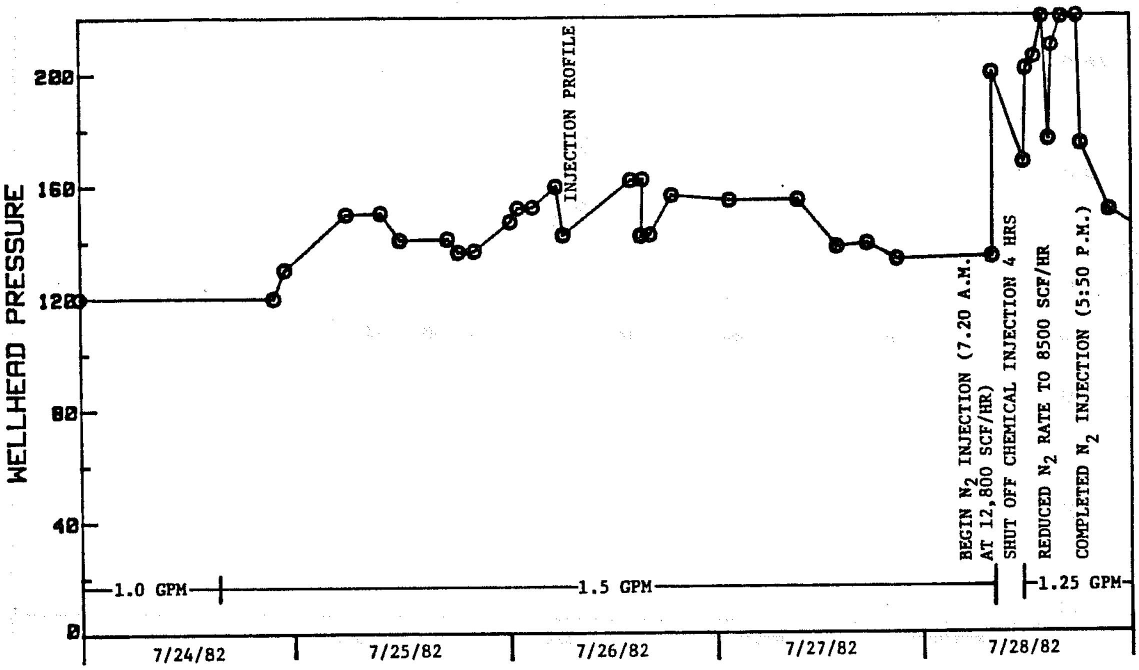


Fig. 4.62: INJECTION WELLHEAD PRESSURE HISTORY DURING FIRST SLUG INJECTION, JULY 24 TO 28, 1982

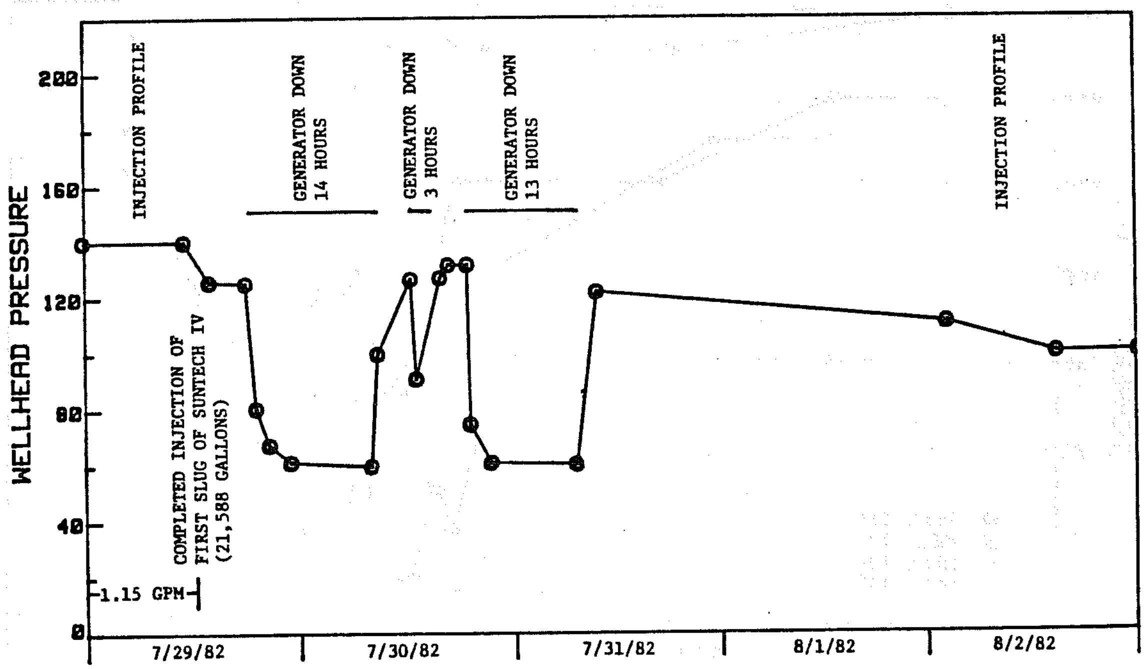


Fig. 4.63: INJECTION WELLHEAD PRESSURE HISTORY DURING FIRST SLUG INJECTION, JULY 29 TO AUGUST 2, 1982

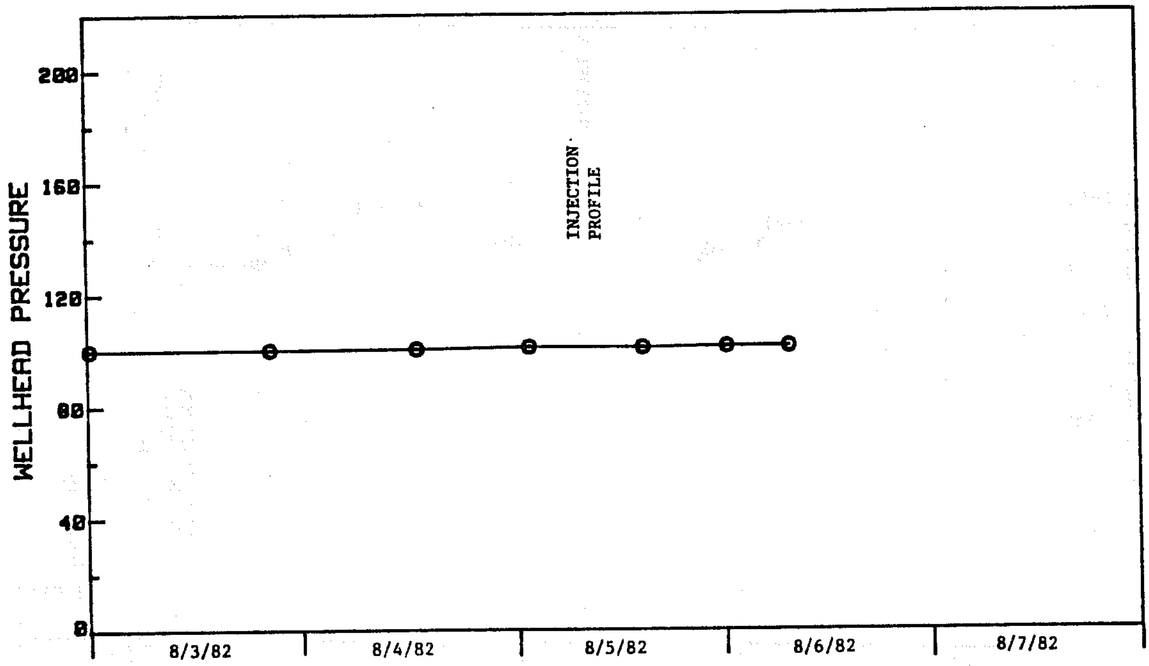


Fig. 4.64: INJECTION WELLHEAD PRESSURE HISTORY DURING FIRST SLUG INJECTION, AUGUST 3 TO 6, 1982

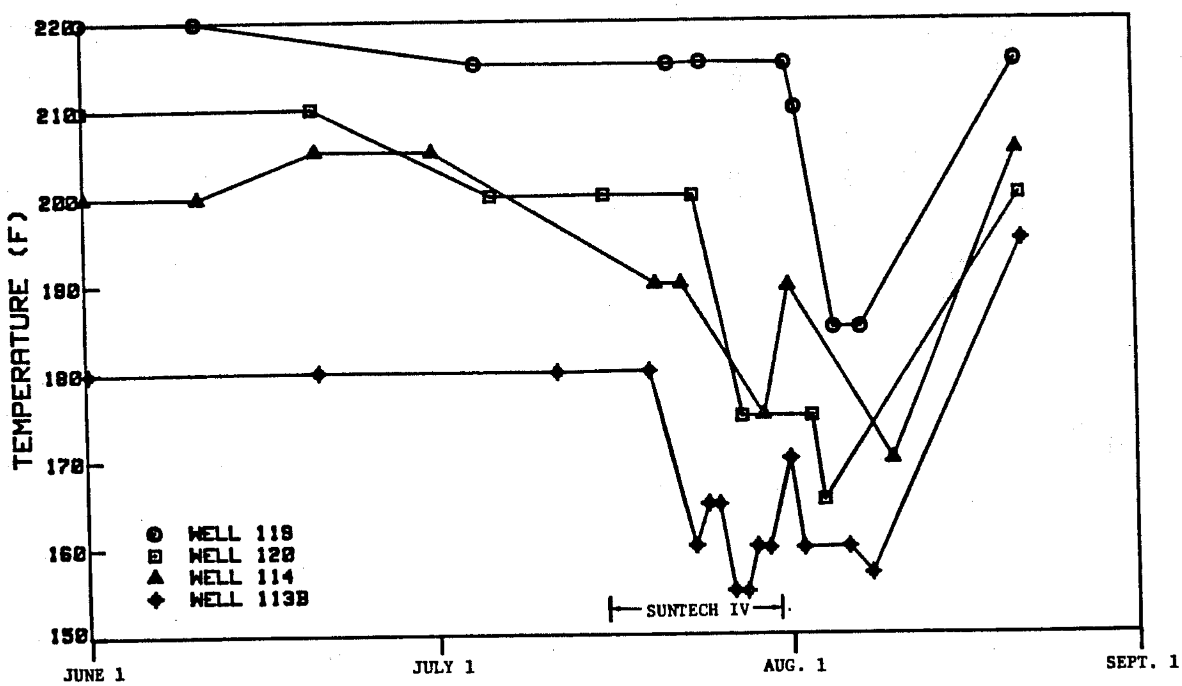


Fig. 4.65: PRODUCTION TEMPERATURE IN WELLS BEFORE AND AFTER FIRST INJECTION OF FIRST SLUG OF SUNTECH IV, JUNE THROUGH AUGUST, 1982

5. WORK DONE SINCE SEPTEMBER 1982 AND FUTURE PLANS

A second slug of Suntech IV was injected during October-November 1982. A new tracer injection was conducted in Well 208, C/O logs were run in Wells 208M and 214M, and injection fall-off tests were conducted in Wells 208 and 214 during October-November 1982. These data are being studied. Tentatively, a total of 60,000 pounds more of 100% active Suntech IV will be injected.

6. CONCLUSIONS

1. Well log correlation shows the reservoir to be composed of lenticular sands sandwiched between layers of shale and/or siltstone.

2. The reservoir has four main permeable layers (termed "slices"). The shale bed above the top most layer (slice 1) is continuous throughout the McManus Lease. However, shale breaks between other slices or their subdivisions are discontinuous over the test area.

3. Established steam/condensate channels and gravity override appear to be detectable by the presence of gamma ray spikes on a gamma ray log, presumably due to leaching and deposition of uranium by steam and steam condensate.

4. Temperature profiles run in the observation wells have been useful in identifying the major steam/condensate swept zones.

5. Major steam swept zones seem to be confined by shale layers displaying unusually high electrical conductivities due to conductive heating.

6. In the control pattern, the bottom of slice 1 appears to show steam channeling while the top of slice 3A shows gravity override. In the test pattern, slice 1 shows steam channeling, slice 2A shows gravity overide, and slice 3A shows severe steam channeling.

7. In the test pattern, slices 1 and 4 appear to be oil rich while slices 2 and 3 are partially desaturated. By comparison, all layers in the control pattern show much less desaturation. In general, the control pattern has more oil saturation than the test pattern, presumably because the control pattern has undergone steam injection for a shorter period.

8. Preliminary log analysis indicates that cores from the observation wells give higher porosity and water saturation compared to log derived values.

9. The tracer injection program to decipher reservoir flow paths has to date not been conclusive.

10. A practical and economical procedure for handling, storing, and injecting Suntech IV surfactant during steam injection has been developed.

11. Suntech IV can be used to generate foam in-situ in a heavy oil reservoir under steam drive.

12. Addition of nitrogen appears to enhance foaming with Suntech IV under reservoir conditions.

13. Injectivity tests show that Suntech IV has the capability of altering injectivity profiles in a steam injection well. However, the exact nature and causes of such alterations are not yet fully understood.

14. Periodic injection well pressure fall-off testing can be used as a useful tool for monitoring the growth of the steam swept volume in a steam drive project. However, the test technique appears to over-estimate both the steam swept volume and heat loss from the reservoir. The permeability-thickness product, md-ft, calculated from the pressure fall-off tests is about 25,000 in the control pattern and 50,000 in the test pattern. Injection wells in both the control and test patterns show positive skin factors.

15. The Carbon/Oxygen log in cased-hole can be used, at least qualitatively, to monitor changes in hydrocarbon saturation in a steam drive project.

16. Metering of oil, gas, and steam condensate need proper calibration and improvement in procedure.

17. Injection of the first slug of Suntech IV has been able to reduce steam channeling and increase oil production.

NOMENCLATURE

a = coefficient of Archie's equation

B = steam formation volume factor, ft^3/scf

C = atomic density of carbon, $atoms/cm^3$

C_a = atomic density of calcium, $atoms/cm^3$

C' = heat capacity, Btu/lb-^oF

c_t = steam two-phase compressibility, psi^{-1}

h = thickness, ft

k = permeability, md

kh = permeability-thickness product, md-ft

L_v = latent heat of vaporization, Btu/lb_m

m = slope of semi-log straight line, psi/cycle

m' = slope of Cartesian straight line, psi/cycle

O = atomic density of oxygen, $atoms/cm^3$

P = pressure, psig

P_{1hr} = semi-log shut in pressure at 1 hr, psig

P_{sz} = average pressure in steam swept zone, psia or psig

P_{wf} = flowing pressure at shut in, psig

q = flowrate, bbls/day

q_s = steam injection rate, scf/d

R = resistivity, ohm-m

R_t = deep induction resistivity, ohm-m

r_w = wellbore radius, ft

S = saturation, fraction

S_i = atomic density of silicon, $atoms/cm^3$

$S_{w_{adj}}$ = Elkin's adjusted water saturation, fraction

s = skin factor

t_p = propagation travel time direct from log, nanosec/m

t_{pma} = propagation travel time of loss free matrix, nanosec/m

t_{ph} = propagation travel time of hydrocarbon, nanosec/m

t_{psh} = propagation travel time of shale, nanosec/m

t_{pw} = propagation travel time of loss free water, nanosec/m

T = average reservoir temperature in the swept zone, ^oF

V_b = bulk volume fraction, 1.0

V_p = swept pore volume, ft^3

V = pore volume, fraction

V_{sh} = shale in a shaly-sand, fraction

ρ = density, lb_m/ft^3

ϕ = porosity, fraction

ϕ_{adj} = Elkin's adjusted porosity, fraction

ϕ_D = density porosity, sandstone p.u.

ϕ_{Dh} = response of hydrocarbon to density log, sandstone p.u.

ϕ_N = neutron porosity, sandstone p.u.

ϕ_{Dsh} = response of shale to density log, sandstone p.u.

ϕ_{Nsh} = response of shale to neutron log, sandstone p.u.

Σ = capture cross section direct from log, capture units

Σ_{ma} = matrix capture cross section, capture units

Σ_{sh} = shale capture cross section, capture units

Σ_w = water capture cross section, capture units

$\Delta\phi_{Nex}$ = excavation effect of neutron log, sandstone p.u.

μ = steam viscosity, cp

SUBSCRIPTS

g = gas

o = oil

r = rock

sh = shale

v = total

w = water

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