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RESIDUAL OIL SATURATION DETERMINATION, WILMINGTON MICELLAR-POLYMER PROJECT

Final Report

Work Performed for the Department of Energy
Under Contract No. EF-77-C-03-1395-M001

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RESIDUAL OIL SATURATION DETERMINATION, WILMINGTON MICELLAR-POLYMER PROJECT

Final Report

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

List of Figures (Continued)

ABSTRACT

The City of Long Beach, California, under contract with the U. S. Department of Energy, conducted a program to obtain residual oil saturation (ROS) data in the HX_a Sand, Fault Block VB, Wilmington Field, the site of a micellar-polymer demonstration project. This program utilized many complementary techniques for determining the ROS in a watered-out unconsolidated sand, typical of many reservoirs in the California Coastal Province. This program was to be performed in two stages. The first, Phase 1, was intended to determine the ROS in an area which had been flooded out during the course of a peripheral waterflood and to make a comparative analysis of current methods for determination of in-situ oil in place. The second stage, Phase 2 of the ROS program, was intended to measure the ROS after tertiary recovery by a micellar-polymer flood; however, the second phase was not carried out for lack of funds. This report describes the diagnostic tools and techniques which have been used to establish ROS. It then presents a comparative analysis of the results obtained using the different techniques.

Inasmuch as the determination of in-situ oil saturation (oil volume) is directly dependent upon the in-situ value for porosity, it is required that the pore volume as a fraction of the reservoir rock be determined before the residual oil equation can be solved. Because of this, much of the study necessarily was concerned with measurement of porosity of the unconsolidated sand.

The method finally used to obtain a very good core recovery in this highly unconsolidated sand is described. The problems of handling and performing core analyses on these sands are

detailed, along with recommendations for special handling techniques.

The values of ROS and other pertinent reservoir parameters determined by each technique are summarized. The advantages and limitations of each method relating to the results obtained are discussed.

Present oil saturation and oil content of the HX_a sand in the Pilot is now believed to be better defined. This conclusion is supported by results obtained for electrical log analysis, analysis of full sized native state cores run under stress conditions, plug core analysis under stressed conditions and a Single-Well Tracer Survey.

INTRODUCTION

PURPOSE

This ROS study was intended to improve the certainty of an in-situ value for residual oil content of the unconsolidated HX_a sand in the Micellar-Polymer Demonstration area (Map 1), Wilmington Field, Los Angeles County, California. In addition, the study was to compare values obtained by several methods and/or tools available for determining residual oil content. This test area had been subjected to an effective peripherial waterflood since 1953. Usually residual oil is referred to as a percentage of the pore volume of a reservoir and oil content (volume) is the product of the estimated pore volume x oil saturation percent. Except for the Carbon/Oxygen log and the Nuclear Magnetism log, all electrical logging tools determine water saturation in the pores of the rock and hydrocarbon content is then assumed to be the difference between one minus the water saturation as a fraction of the pore volume. Thus it follows that the most nearly true value for porosity in-situ must be known before a best estimate of oil volume in place can be obtained. Likewise in core analysis, the true in-situ porosity (pore volume as percent or fraction of bulk rock volume) is essential in the estimation of fluid saturation values and also as a direct comparison and/or check of electrical log-derived values.

In summary, then, determination of in-situ porosity is an absolute requirement for the best estimate of the residual oil in place. It follows, therefore, that much of this study had to concentrate on different laboratory procedures for handling unconsolidated core material to provide representative porosity values for the sand in-situ which is liquid-filled and under overburden load.

Phase 2 was to be performed at the conclusion of the project to determine the residual oil after tertiary recovery. However, because of depletion of funds, Phase 2 had to be canceled.

SCOPE OF STUDY

Phase 1 includes data obtained from a special coring and core analysis program, open-hole and cased-hole electrical logs, and a Single Well Tracer Test. The opportunity to obtain this extensive supplemental information occurred when producer T-103 was redrilled in October 1978. Availability of these additional reservoir measurements was made possible by the U. S. Department of Energy (DOE) and provided for by Contract No. EF-77-C-03-1395-M001 of October 20, 1978 between DOE and the City of Long Beach. This report "Residual Oil Saturation Determination for Wilmington Micellar-Polymer Project," together with core analyses from three of the other wells and open-hole electrical-log suites from five other project wells, provides the data available for estimating in-situ porosity and ROS after waterflooding, and at the start of the tertiary recovery project.

BACKGROUND INFORMATION

Prior to 1965, the accepted porosity values for the unconsolidated sands in the upper three zones (depth 2000 to 3500 feet) in the Wilmington Field were 34 to 36 percent. These values were based upon core analyses run with little to no compaction pressure. In the early drilling of the Long Beach Unit (1965 to 1966) the practice of running core analysis porosity tests with a sleeve compaction pressure of 350 psi was adopted. This pressure was chosen because it resulted in less scattering of data points than with a sleeve pressure of 250 psi. Additional values were determined on a number of samples under a triaxial confining pressure to 1500 psi. The resulting porosity and permeability values were less than obtained with the 350-psi sleeve pressure.

In 1972, a few redrill wells in Old Wilmington were logged using the Compensated Density and Compensated Neutron logs in addition to the Dual Induction, Spontaneous Potential, Gamma Ray, and Caliper Logs. These data were computer processed by Schlumberger, using its Saraband program. The porosity values (based principally on cross-plot of the neutron and density porosity) were considerably less than 30 percent. Subsequently, old electrical logs available from aquifer water-injection wells were reviewed and porosity calculated for sands having 100-percent water saturation using the Archie method[1]. This calculation resulted in values averaging less than 30 percent. For the HX_a sand in Upper Terminal VB, the average indicated porosity was 29 percent for eight wells. Because one of the prime needs of this Micellar-Polymer Demonstration Project was (and is) to determine the current in-situ values of porosity and oil saturation[2], a concerted logging and coring program was applied.

In about 1958, Norris Johnston[3] developed a uniaxial pressure core holder and advocated the running of porosity, permeability, capillary pressure, and relative permeability tests of core samples under elevated pressures to simulate overburden load. However, such practice was not accepted by the industry at that time. Engineers to whom such data were submitted refused to believe the lower values for permeability and for porosity.

Since 1962, a number of papers have appeared in the literature, indicating that conventional core analysis porosity values are too high and have resulted in an overestimation of oil in place[4,5,6,7,8,9,10,11 and 12].

RESERVOIR DATA

Four of the ten wells in the Micellar-Polymer Project were cored. Special electrical logs were run in eight of the wells.

CORE DATA

The HX_a sand has been cored in four wells, using a plastic-sleeve core barrel. Cores were cut into 3-foot lengths on the rig floor, quick-frozen, and then transferred to the laboratory for analysis or stored in a deep-freeze locker for later analysis. Following is a summary of cores obtained:

Well	Date	Diam. 1/ Inches	Gross Ft. HXa Sand Cored	Recovered	%	Analyzed by
FT-1	7/77	5	55	36	65	2/ & 3/
T-102	3/78	5	50	9	18	3/ & 4/
T-104	4/78	5	48	34.3	71	Stored: 2/
T103 Rd	10/78	3.2	55	52	95	5/

1/ I.D. of plastic tube. I.D. of core head 4-3/4 inches for the 5-inch sleeve. Core expands to fill tube.

2/ Petroleum Testing Services, Inc., Santa Fe Springs, CA.

3/ Marathon Oil Company's Denver Research Center

4/ Core Laboratories, Inc., Long Beach

5/ Core Laboratories, Inc., Oklahoma City

Initial plans contemplated coring Wells FT-1 and T-102 only for the purpose of obtaining core material of maximum diameter to be used in micellar-polymer displacement tests in Marathon Oil Company's Denver Research Center laboratories. Because of the inadequate core recovery from T-102, T-104 was also cored in order to have more large-diameter core material. When it became necessary to redrill T-103 from the surface, the ROS determination contract amendment was adopted for the purpose of obtaining additional reservoir data.

The high recovery from the redrilled T-103, designated as T-103-Rd, was attributed to the experience of the coring contractor's representative in coring unconsolidated formations, together with the restriction that each core run be 6 feet or less. The poor core recovery from T-102 appeared to have resulted from the lack of experience of the coring contractor's representative in coring unconsolidated formations.

The purpose of freezing the core material in the plastic sleeve while on the rig floor and maintaining the core in a frozen state until it was analyzed was to minimize rearrangement of sand grains. While this procedure should minimize movement, it does not prevent movement. The fact that the formation cut with a 4-3/4 inch I.D. head expanded to fill the 5-inch I.D. tube illustrates the movement.

ELECTRICAL LOGS

Five of the wells had to be redrilled from the surface. This procedure made it possible to obtain the following data:

1. Dual Induction Laterolog with Spontaneous Potential.

2. Simultaneous Compensated Neutron and Compensated Formation Density with Gamma-Ray and Caliper.

3. Computed Saraband Log (graphical) showing reservoir properties.

4. Tabulated printout of computed log.

5. Engineering data printout.

The other five completions were millouts in the HX_a sand only, which precluded the use of most open-hole logging tools. However, some special logs were run on an experimental basis.

Wells FT-2 and T-103

The Dresser Atlas Carbon-Oxygen Log, Compensated Neutron, and Dual-Detector Neutron Lifetime Logs were run in the cased hole. After mill-out, the Dual Induction Focused Log and Spontaneous Potential were run. In T-103, a Compensated Densilog also was run. From these, Dresser computed its Epilog presented in graphical and tabular forms. The output data were stamped "experimental".

Well FT-4

Schlumberger ran Dual Induction Laterolog, Spontaneous Potential, and Caliper Logs.

Wells T-100 and T-105

Dresser Atlas ran its Dual-Induction Focused Log and Spontaneous Potential in both wells and the Densilog in T-105.

When T-103 was redrilled from the surface, it became opportune to run several additional logs as well as a single-well tracer survey to refine the determination of residual oil. Following is a summary of logging programs including the redrill of T-103:

Well	Month	Year	Special Logs	Computer Analysis	Logging Company
Surface Redrills					
FT-1	July	1977	Yes	Saraband	Schlumberger
FT-3	Jan.	1978	Yes	Saraband	Schlumberger
T-101	Feb.	1978	Yes	Saraband	Schlumberger
T-102	Mar.	1978	Yes	Saraband	Schlumberger
T-104	Apr.	1978	Yes	Saraband	Schlumberger
Mill-out Completions					
FT-2	Dec.	1977	Yes	Epilog	Dresser Atlas
FT-4	Feb.	1978	No		Schlumberger
T-100	Jan.	1978	No		Dresser Atlas
T-103	Mar.	1978	Yes	Epilog	Dresser Atlas
T-105	Apr.	1978	Yes		Dresser Atlas
Special for ROS Project					
T-103-Rd	Oct/Nov.	1978	Yes	Various Epilog	Schlumberger Dresser Atlas GO Intnl.

Well T-103-Rd

The following logs were run in T-103-Rd:

A. Open-Hole Logs

1. Micro-Spherical Focused Logs (MSFL)
2. Dual-Induction Laterolog (DIL-LL8)
3. Bore Hole Compensated Sonic (BHC)
4. Formation Density Compensated-Compensated Neutron Log-Gamma Ray (FDC-CNL-GR)
5. Microlaterolog-Microlog (MLL-ML)
6. Dielectric Constant Log (DCL)

B. Cased-Hole Logs

1. Dual-Spacing Thermal Neutron Decay Time Log (TDT)
2. Dual-Detector Neutron Lifetime Log (NLL)
3. Carbon-Oxygen Log (C/O)

GO Wireline Services advised that the Dielectric Constant log did not respond in the HX_a sand in T-103-Rd because formation resistivity must be above 10 ohms before a reliable measurement can be obtained. In a resistivity range of 5 to 10 ohms, measurement can be obtained, but the values are questionable. Below 5 ohms, dielectric measurements with their present tool are not valid. These limitations appear to rule out applicability of the dielectric tool for determination of ROS after waterflooding in Wilmington.

The Electro-Magnetic Propagation Tool (EPT) had been scheduled, but no tool was available.

RESULTS FROM CORE ANALYSES

SUMMARY DATA

Average core analysis data by well is given in Table 1. For each well, results are presented in two general groupings: (1) data from routine core analysis, and (2) porosity and permeability values at different triaxial confining pressures. After the test results from T-103-Rd were studied, it was deemed necessary to segregate porosity values depending on whether they resulted from wet or dry compaction.

Early in the micellar-polymer project, a significant difference in porosity values for samples compacted dry versus samples compacted wet was apparent. Marathon's early work, using old core material which had been cleaned and dried, found that a dry sand pack did not compact nearly as much at 1400 psi as when the pack was wet. The full native state core disc samples used for the M-P displacement tests from wells FT-1 and T-102 should provide the most representative core analyses values for porosity at 1400 psi uniaxial confining pressure because of the large size of sample. The porosity reported for the full core samples and the plug samples from wells FT-1, T-103-Rd and T-104 include bound clay water which approximated from 1.0 to 1.2 porosity percent.

In December 1979 Mr. Thomas C. Wesson, Technical Project Officer for the Department of Energy, authorized additional clay mineral laboratory analysis of the sand from T-103-Rd. The principal purpose of the additional tests was to obtain direct measurements of bound clay water. The laboratory method is described in a paper by Bush and Jenkins.[13] Subsequently, the adsorbed clay water was determined on 32 samples throughout the vertical section. These values, together with the corresponding cation exchange capacity (CEC) from the standard correlation, were reported. Five of the samples were then selected for determination of (1) CEC by wet chemistry, (2) clay mineral content by X-ray diffraction for each of the clay, silt, and sand fractions, and (3) scanning electron microscope (SEM) photographs.

The resultant adsorbed water values account for from 1.0 to 1.2 porosity percent of the previously reported helium porosity values determined at 0 to 2000 psi confining pressure. The higher porosity values resulted because the bound shale water had been expelled before helium porosity was measured in all samples which were not dried in a humidity-controlled oven.[14] The only samples for which all adsorbed water was not lost by laboratory procedures used were the ten samples from T-102 (Table 3).

Core From Well FT-1

Two sets of 14 plug samples each from Well FT-1 were analyzed by Petroleum Testing Service. As shown in Table 2, the first set had an average helium porosity of 39.6 percent determined at 90 psi Hassler sleeve pressure (uniaxial), while the second set had a liquid porosity averaging 40.8 percent determined at 0 psi confining pressure. Helium porosity and permeability to air under triaxial loading pressures of 350, 800, 1600, and 2000 psi were run on the second set of samples. The average value of porosity decreased from 38.2 percent at 350 psi to 33.0 percent at 2000 psi. The permeability to air decreased from 802 millidarcies at 350 psi to 386 millidarcies at 2000 psi. As shown in Figure 1-A, the permeability to air declined with the logarithm of confining pressure. A similar relationship between porosity percent and confining pressure for the samples which were compacted dry is illustrated by Figure 1-B.

Core From Well T-102

The results of analyses of two sets of five samples each are listed in Table 3. Permeability, helium porosity, and oil and water saturations were determined after using a 750 psi triaxial pressure to seat the samples in metal sleeves. Permeability and porosity were then determined under a confining pressure of 1600 psi. The second set of samples (dry) was tested for permeability and porosity at confining pressures of 350, 800, 1600 and 2000 psi. Shown in Figures 2-A and 2-B is the relationship between permeability and porosity, respectively, for the range of confining pressures used. Average permeability decreased from 612 millidarcies at 350 psi to 333 millidarcies at 2000 psi. Helium porosity decreased from 33.5 percent at 350 psi to 28.2 percent at 2000 psi.

Core From Well T-104

Two sets of seven samples each were analyzed by Petroleum Testing Service (Table 4). The oil and water saturations were determined on the first set based on liquid porosity values. The average liquid porosity was 40.6 percent determined at 0 psi confining pressure. The liquid-filled samples were subjected to 1600 psi confining pressure and pore volume reduction determined by volume of liquid expelled from each sample. The average for the seven samples was 30.8 percent. On the second set of samples (dry), helium porosity and permeability to air were determined at 350, 800, 1600, and 2000 psi.

In Figure 3-A is shown the relationship in porosity at 1600 psi between samples compacted dry and those compacted wet. Average value for wet compaction is only 0.91 of the dry value or 30.8 percent compared to 33.7 percent for dry compaction. The relationship between permeability and porosity with confining pressure for samples compacted dry is illustrated by Figures 3-B and 3-C. Permeability averaged 648 millidarcies at 350 psi and 315 millidarcies at 2000 psi. Porosity averaged 37.7 percent at 350 psi and 32.9 percent at 2000 psi.

Core From Well T-103-Rd

A series of special tests were run on the cores from Well T-103-Rd. Cores were shipped to Core Laboratories, Inc., in Oklahoma City for analysis. The frozen core was slabbed and then photographed, using both incandescent and ultraviolet light. The delineation between oil sand and shale is much sharper under ultraviolet light. When these photos are studied, it is easy to differentiate between oil sand and shale. The slabbed section was mounted in plaster of paris and returned to the Department of Oil Properties in Long Beach for detailed geological description.

Two sets of samples (A and B) were taken from each foot of core. Routine core analyses (oil and water saturation, porosity and permeability) together with porosity and permeability measurements with 1600 psi dry confining pressure were determined on 43 samples from Set A. Liquid porosity values at zero psi pressure were determined on 45 B samples after being subjected to 1600 psi confining pressure and pressure then relaxed to zero psi. Starting at the bottom, each of the first ten were drilled from the frozen core using liquid nitrogen. Because the plugs were removed from the core bit with difficulty, all subsequent samples were taken using a cork borer after permitting the core to partially thaw.

A third set of eight C samples was taken for dry compaction tests, a fourth set of eight D samples was taken for wet compaction tests, and a fifth set of eight E samples was taken for waterflood susceptibility tests to be run under a confining pressure of 1600 psi. The C, D, and E samples were taken from the same foot of core as the corresponding numeric prefixes for the A and B samples. The core contained about 10 inches of highly indurated calcareous oil sand from a depth between 2939 and 2940 feet (Sample 32). Initially C, D, and E samples were taken from this interval. Subsequently, replacements for Sample 32 were secured for the C and D sample sets so that each set of eight would be more representative of the total sand section.

T-103-Rd, A Samples

Results of analysis for the A samples are given in Table 5. These data include permeability at 200 psi, grain density, and two sets of porosity and core liquid saturation values, i.e. at low pressure and at 1600 psi confining pressure after dry compaction. Porosity was determined by two methods: (1) helium grain volume and Archimedes bulk volume (wet) at atmospheric pressure, and (2) helium pore volume and helium grain volume (dry) at 200 psi pressure. Preliminary results of analysis were based on the Archimedes bulk volume. Subsequently, saturation data were calculated using the helium porosity values. Both sets of data are included in Table 5. The average porosity values are 41.8 percent using the Archimedes bulk volume and 39.0 percent for the helium porosity. Use of the helium porosity to calculate saturation changes the oil saturation from 18.9 to 21.1 percent, an increase of 1.12; however, the oil content as barrels per acre-foot changes from 613 to 638, an increase of only 1.04. This serves to illustrate the sensitivity of oil saturation percent to porosity.

Figures 4-A, 4-B, and 4-C are provided to show the relationship between helium porosity and wet porosity, helium bulk volume and Archimedes bulk volume, and the difference the porosity method makes in total liquid saturation. In each of these figures, the triangular points are for the 10 samples drilled from the frozen core.

T-103-Rd, B Samples

The B samples were to be used for determining porosity at 1600 psi confining pressure for wet compaction. The fresh core plugs were subjected to 1600 psi in the triaxial pressure cell, and the volume of liquid expelled from each sample was measured and recorded. However, the procedure did not include testing for the presence of residual gas space in the sample before the sample was removed from the pressure cell. These B samples were removed from the triaxial holder, vapor extracted in a Dean-Stark apparatus, and dried in a non-humidity oven. Grain volume was measured next using an extended-range helium porosimeter. Samples were then evacuated, saturated with brine, and subjected to 2000 psi pressure for four hours to ensure complete liquid saturation; whereupon, liquid porosities were determined at atmospheric pressure.

T-103-Rd, A Versus B Samples

Porosity, permeability, and bulk volume values for the A and B samples are compared in Table 6. Helium porosity for the A samples compacted dry under 1600 psi is included along with the two sets of porosity values provided in Table 5.

Three sets of porosity values are given for the B samples, all of which are classed as wet values.

The three porosity methods with resultant average values are as follows:

1. Helium grain volume and Archimedes bulk volume -- 33.9 percent.

2. Liquid pore volume and helium grain volume -- 34.5 percent.

3. Liquid pore volume and Archimedes bulk volume -- 35.2 percent.

Figures 5-A through 5-D are graphic comparisons of the different porosity and bulk volume values obtained by the three different methods. These illustrate more variation in values for different laboratory methods than desirable.

T-103-Rd, C Versus A Samples

Table 7 is included to compare helium porosity values for the A and C samples at 200 psi and the A and C duplicates at 1600 psi. Figures 6-A and 6-B are used to illustrate the data for the A and C samples. At 1600 psi, the average values are the same (33.4 percent) which are in good agreement with the average of 33.1 percent for all of the A samples. The average at 200 psi is 39.4 percent for the A samples versus 37.4 percent for the C samples.

T-103-Rd, D Samples

Porosity results for the D samples which were compacted wet are given in Table 8. In preparation for testing, the samples were extracted and dried in a non-humidity oven. Helium porosity (helium grain volume and helium pore volume) was determined, and the samples were resaturated with brine. Liquid pore volume was determined by weight difference in the dry and wet samples. Samples were placed in a triaxial pressure cell for measurement of porosity at confining pressures of 350, 800, 1600, and 2000 psi. Reduction in pore volume was determined by measurement of brine expelled at each pressure. A preliminary report by CLI on results of these tests was based on the initial liquid pore volume. A subsequent report was issued based on initial helium pore volume. The last two columns show these latter values which are believed to be the most applicable because of the good agreement with six duplicate E samples at 1600 psi. Following are the comparative data.

	Porosity % at 1600 psi	
	"D"	"E"
2	31.3	29.7
7	31.9	31.6
11	29.4	30.8
16	29.7	29.3
23	30.4	32.0
43	30.1	30.6
Avg	30.5	30.7

T-103-Rd Waterflood Tests, E Samples

Waterflood susceptibility tests (WFST) under confining pressure of 1600 psi were completed on six of the E samples. Summary data are presented in Table 9. These data include permeability to air, porosity calculated from grain volume, and the final saturations determined from the Dean-Stark procedure. Average porosity for the six samples was 30.7 percent compared to 30.5 percent for six duplicate D samples.

Irreducible water saturation after oil flooding was 32.8 percent, and permeability to oil was 102 millidarcies. Irreducible oil saturation after waterflooding was 30.3 percent, and the permeability to water 20 millidarcies. Oil recovered was 36.9 percent of the pore volume.

In the lower part of the table, average data from prior tests (1958 to 1961) on seven samples are presented for comparison. Porosity and permeability values of the old data for which no confining pressure was used are substantially higher. Initial water saturation and final oil saturation values for the old data are lower and oil recovered greater.

Figure 7-A is a plot of produced water-oil ratio versus oil recovered as percent of pore volume. Data for each of the six samples are shown, together with the average curve. Figure 10-B is used to compare the average curve for the six samples with that of the prior WFST data and with the actual oil recovery for the $HX_{a,b,c}$ sands of Upper Terminal VB. Up to a produced water-oil ratio of 10, the two WFST curves are about the same, even though porosity, permeability, and end-point saturation values are substantially different. However, the new data do not show the break to the right at the 10 water-oil ratio indicated by the old data.

Figure 8 shows the relative permeability curves reported for the six waterflood susceptibility tests.

T-103-Rd, Air-Brine Capillary Pressure and Formation Resistivity Index

Initially, air-brine capillary pressure tests were run on eight plugs taken from the B set of samples. Resistivity was measured at water saturation varying from 23 to 72 percent. Resistivity index was calculated and reported by Core Laboratories (Table 10 and Figure 9).

Water saturation values at the low displacement pressures were erratic. Consequently, Core Laboratories reran the eight samples plus two additional ones. Data for the 10 samples are shown in Table 11 and Figure 10. Brine saturations at 35 psi ranged from 22.5 to 33.0 percent. However, the validity of the data is questionable because the samples were compacted at 1600 psi but then were extracted, dried, and resaturated under vacuum. This procedure resulted in porosity values ranging from 32.5 to 37.8 percent, much higher than obtained under 1600 psi overburden pressure on the adjacent D set of core plugs. The error in resistivity index, however, would not be as great as for the resistivity value because the R index is defined as:

$$\text{Resistivity Index} = \frac{R_t}{R_o} \quad \begin{array}{l}\text{(measured on capillary pressure plug @ 0 psi)} \\ \text{(measured @ 1600 psi } S_w = 100)\end{array}$$

Referring again to Figure 9, the saturation exponent "n" was determined to be 2.18 from the slope of the visual best-fit line. However, these data are based on an average porosity of 35.0 percent, which is too high to be representative of in-situ conditions. Thus, the "n" and "m" factors measured on core from T-103-Rd are not applicable in calculating in-situ ROS by the Archie-type empirical equation.

T-103-Rd, Permeability to Air and Porosity (Wet and Dry) Versus Confining Pressure

Helium porosity and permeability to air for the eight C samples at confining pressures of 200, 350, 800, 1600, and 2000 psi are given in Table 12. Figure 11-A is used to show the relationship between logarithm of permeability and confining pressure. Shown in Figure 11-B are similar data for average porosity values and confining pressure for the eight C samples compacted dry, for the eight D samples compacted wet and the six E waterflood samples compacted at 1600 psi (wet). The difference in porosity between dry and wet compaction increases with the increase in pressure. It is believed that this difference results from the lubrication effect of the liquid on the sand grains.

T-103-Rd, Formation Factors

Formation factors were run on each of the B samples at 0-psi and 1600 psi confining pressure. Samples had been saturated with brine having 0.233 ohm-meter resistivity at 76°F. Porosity values compatible with the formation factors determined at 0 psi were obtained. However, because of the failure to secure usable porosity values at 1600 psi for the B samples, only nine values for the D samples are available. These data, together with grain density, are given in Table 13. Included are the correlative logging depths based on the 10-inch microlog.

The formation factor and porosity data are shown in Figure 12, together with average relationships shown in Schlumberger's booklet of Log Interpretation Charts. Except for the core porosity values, the data included in Table 10 were furnished to Schlumberger prior to its re-analysis of the six Saraband logs.

Three of the six data points for the 1600 psi confining pressure fall close to the two curves for soft formations; i.e.,

$$F_R = \frac{0.62}{\phi^{2.15}} \quad \text{and} \quad F_R = \frac{0.81}{\phi^2}$$

The other three points are closer to the relationship,

$$F_R = \frac{1}{\phi^2}$$

Based upon the two curves for soft formations, the formation factors under 1600 psi confining pressure ranging from 7 to 14 correspond with a porosity range of 23 to 33 percent.

Excluding sample 32-B, the dense limestone streak of 1 foot, the average formation factor for 42 B samples under 1600 psi confining pressure is 9.66. The average formation factors calculated from electrical logs taken in 1953-1959 for wells in the north and south flank aquifers range from 8.1 to 12.3 and average 9.5. This could mean that the 1600 psi confining pressure is not unreasonable.

T-103-Rd, Adsorbed Clay Water Tests and CEC Values

Thirty-two preserved sand samples were sent to Core Laboratories, Inc., Dallas, Texas, in December 1979 for adsorbed water determinations and CEC values based upon CLI's standard correlation.[16] Five samples then were selected for

1. CEC determination by wet chemistry.

2. Clay mineral identification by X-ray diffraction for each of the clay, silt, and sand fractions.

3. SEM photographs.

Adsorbed water index[13] is determined by dividing the unhumidified dry weight (sample dried in conventional oven at 105°C) by the humidified dry weight (sample dried in 40 to 50 percent relative humidity oven at 60° to 63°C). Any bound clay water is driven off in the conventional drying process utilizing a convection oven.[18]

The average adsorbed water index is 0.9938 with individual values ranging from 0.9893 to 0.9975. The adsorbed water values per unit of sand for a grain density of 2.67 are as follows:

	gm water/gm sand	ml water/ml grain volume
Average	0.0062	0.0166
Range	0.0103 to 0.0025	0.0275 to 0.0067

The average clay water volume of 0.0166 ml per grain volume is used to correct the helium porosity for loss of adsorbed water as follows:

Confining Pressure PSI	He Por % Reported For D Samples	Clay Water % of Bulk Volume	Effective Por %
0	38.2	(1-0.382) x 0.0166 x 100 = 1.03	37.2
350	34.7	(1-0.347) x 0.0166 x 100 = 1.08	33.6
800	32.4	(1-0.324) x 0.0166 x 100 = 1.12	31.3
1600	30.5	(1-0.305) x 0.0166 x 100 = 1.15	29.3
2000	29.2	(1-0.292) x 0.0166 x 100 = 1.18	28.0

The CEC values for the 32 samples based on the adsorbed water index ranges from 3.8 to 11.5 and averages 7.58. The five cleaned samples analyzed by wet chemistry gave values ranging from 4.32 to 7.49, with an average of 5.78, which is only 76 percent of that estimated by adsorbed water index for the same samples. Darrell C. Bush of Core Laboratories is of the opinion that the excess water probably comes from diatomite in the sand. This material has little or no CEC value and it is not identified by X-ray diffraction.

Core Analysis by Marathon Oil Company, Wells FT-1 and T-102

A summary of porosity and saturation values is shown in Table 14. These data were obtained during the displacement tests required for design of the micellar-polymer system. Each sample consisted of a disk 2-inches thick sawed from the frozen core. After a 1/8-inch hole had been drilled through the center of the disk, the sample was inserted into a high-pressure core holder. A pressure of 1400 psi was applied and maintained on the top surface. All flow tests were from the center hole to the periphery. Values shown include porosity and oil and water saturation of the frozen core, together with porosity of the compacted samples, residual water after oil flood, and residual oil after waterflood. Permeability to oil at residual water and to water at residual oil are included. There was a substantial variation in the number of samples available from each 3-foot tube of core. Because of this variation, the average for each 3-foot section has been calculated and then a weighted average value per foot determined.

The 1400-psi loading pressure was specified as approximating the initial net overburden load at the top of the HX_a sand. This pressure equates to a gradient of 0.93 psi per foot of depth less initial reservoir pressure. Subsequent bore hole gravity meter surveys for two wells in the Long Beach Unit indicate that a gradient of 0.9 psi per foot of depth gross loading to top of the HX sand is more applicable, thus indicating an initial net overburden load of 1320 psi. In 1953 reservoir pressure in the M-P area approximated 670 psi so that maximum net load could have been nearly 2000 psi. There is considerable uncertainty and disagreement among geologists and soil mechanic experts as to how much of the pressure decline in the reservoir is transferred to additional net load for the system. If only 42 percent of the pressure decrease was transferred, the maximum net effective load would have been about 1600 psi; if 72 percent was transferred the maximum net effective load would have been about 1800 psi.

The average porosity values of 30 percent for FT-1 and 29 percent for T-102 each need to be adjusted to a loading pressure of at least 1600 psi. First, though, there is another indeterminate factor in these values caused by the clay content of this sand. In the determination of final oil and water content, each sample was subjected to a temperature of 220 to 230°F for 36 hours while in the Dean-Stark extraction unit. This temperature is sufficient to drive off all adsorbed clay water.

J. M. Hartshorne[18] of Marathon Oil Company, who had done the mineralogical work on several samples of HX_a sand, reported minimum clay content of 7 percent and with a maximum average of

12 to 15 percent. This means that at least 6 cc's of water could have come from the minimum clay content in the extraction process. Such a loss of clay water for FT-1 would mean that the porosity available for hydrocarbons and interstitial water was 29 percent at 1400-psi confining pressure rather than 30 percent. Subsequently, results of the 32 adsorbed water tests run by Core Laboratories, Inc., in Dallas for T-103-Rd appear to confirm bound clay water approximating 1.2 porosity percent and in turn a porosity value of 28.8 percent for FT-1 and 27.8 percent for T-102 after correcting for loss of clay water.

Summation of Permeability and Porosity Laboratory Data - All Wells

A summation of all permeability and porosity data for the four cored wells at the different confining pressures is presented in Table 15. The porosity data are segregated between samples compacted dry and samples compacted wet. Porosity values corrected for adsorbed water are shown together with values reported directly by the respective laboratory.

Values averaged by well but not corrected for clay water are shown in Figures 13-A and 13-B. These plots again illustrate the exponential relationship of initial compaction pressure with permeability and with porosity for this unconsolidated sand. Figure 11-B further illustrates that compaction of the liquid-filled samples was significantly greater than for the dry samples.

The average porosity values for all samples under confining pressures and corrected for bound clay water are as follows:

No. Samples	1400 psi	1600 psi	2000 psi
73 wet 1/	28.3		
21 wet		29.5	
8 wet			28.0
39 dry		31.9	30.9

1/ 2"h x 5"d disc samples under uniaxial loading. All others were plug samples approximately 1"d x 1-1/2" under triaxial loading.

Probable Core Porosity and Oil Saturation Under Overburden Load at Maximum Pressure Depletion

As noted previously, the initial overburden load should have approximated 1320 psi, and the maximum could have approximated 2000 psi if the maximum pressure reduction in this area of the reservoir was fully transferred to additional overburden loading. Core porosity values for samples compacted wet at 1400 psi are available for two wells (FT-1 and T-102), at 1600 psi for two wells (T-104 and T-103-Rd), and at 2000 psi for one well (T-103-Rd). The porosity wet compressibility factor going from 1600 psi to 2000 psi for T-103-Rd is calculated as follows:

$$c_f = \frac{1 - 28.0/29.3}{2000 - 1600} = 111 \times 10^{-6} \text{ per psi}$$

Using this compressibility, the applicable porosity correction factors are as follows:

1400 to 1600 psi = 0.978
1400 to 1800 psi = 0.956
1400 to 2000 psi = 0.933
1600 to 1800 psi = 0.978
1600 to 2000 psi = 0.956

From these factors, the porosity values from wet compaction are adjusted to the higher overburden pressures as listed:

Well	Porosity Percent 1400 psi	1600 psi	1800 psi	2000 psi
FT-1	28.8	28.2	27.5	26.9
T-102	27.8	27.2	26.6	25.9
T-103-Rd		29.4	28.8	28.1
T-104		29.6	28.9	28.3
Average		28.6	28.0	27.3

Comparing the above average porosity values with those obtained from the computed Saraband values for these four wells shows the best agreement to be at 1600 psi. The core oil saturation values corrected to the porosity values under this loading pressure are as follows:

	Conventional		Reservoir Oil Saturation Adjusted to Overburden Load of 1600 psi		
	Porosity Percent	Oil Sat. Percent	Porosity Percent	Oil Sat. Percent	Oil Content Bbl/A.Ft.
FT1-Plugs 2/	40.2	21.4	28.2 1/	38.8	849
FT1-Disc	42.3	15.6	28.2	30.7	672
T-102 Plugs	32.1	26.4	27.2 1/	35.4	747
T-102 Disc	40.9	17.9	27.2	35.1	741
T-103-Rd.Plugs	40.4	20.2	29.4	34.9	796
T-104 Plugs	40.6	17.4	29.6	30.0	689
Avg. by wells	39.7	19.6	28.6	33.7	747

1/ No plugs compacted wet so use value for disc samples.
2/ 14 samples.

Thus, the average oil saturation from core analysis for four wells when adjusted for formation volume factor and to a porosity of 28.6 percent approximates 33.7 percent and 747 barrels per acre foot. This oil value is in close agreement with the laboratory waterflood residual oil saturation for 73 disc samples from FT-1 and T-102.

Inasmuch as oil is a measured volume in core analysis, the adjustments for different porosity values are made as follows:

$$\text{Adj. Oil Sat.} = S_{oi} \times \frac{\phi_1/\phi_2}{(1-\phi_1) \div (1-\phi_2)} \times b_o$$

where ϕ_1 = conventional core porosity
ϕ_2 = compacted porosity
b_o = 1.06

Example T-103-Rd Plugs:

$$S_o \text{ @ 1600 psi} = 20.2 \times \frac{40.4/29.4}{(1-0.404) \div (1-0.294)} \times 1.06 = 34.9$$

Any oil lost from the core either by flushing ahead of the bit or from pressure reduction would cause the preceding reservoir numbers to be low. However, loss of oil should have been negligible (2 to 4 porosity percent) because of the current stage of depletion in this sand, as indicated by (1) high produced water-oil ratio, (2) the expansion of the core between bottom of the hole and the surface, (3) minimal gas in solution, and (4) the 18° API oil gravity.

RESULTS FROM ELECTRICAL LOGS

SUMMARY

A summary of the electrical log analyses for the ten wells in the pilot area is given in Table 16. Included are values from the Engineering Printout as well as the Customer's Listing. The average values for each well are segregated into two groups. The first is for the six wells which were redrilled from the surface and in which open-hole logs could be run. The second group is for mill-out completions which negated the use of most open-hole logs. Well T-103 was a mill-out; however, because of casing failure, the well was redrilled from the surface.

Saraband analyses are available on all six of the surface redrills.

Early in 1979, Schlumberger agreed to review and reprocess the Sarabands for the purpose of normalization of the data and to ensure consistency in selection of the Saraband parameters. In August of 1980 the T-103-Rd core data indicated the need for further reduction in clay content and a special field normalization was done (August 20, 1980) using Schlumberger's new multi-dimensional normalization program for all six wells. The previous rerun was a "by hand" method with an accuracy of 2± porosity units. The machine system is thought to reduce the error to 1/2± porosity units. T-101 calculated clay and shale volume still appears somewhat high and T-103-Rd grain density value appears high. Dresser Atlas reran the Epilogs on three wells in June, 1979. This reprocessing applied specifically to the HXa sand.

Open Hole Logs

Schlumberger electrical logs and Saraband analyses were utilized in all five pilot wells redrilled from the surface. The reason for limiting this logging to a single service company was to provide maximum consistency among wells and for direct comparison of similar log data from other wells in the general area.

In T-103-Rd the Saraband suite of logs likewise was run to be directly comparable with data from the other five wells. In addition, the Schlumberger TDT log and the Dresser Atlas Epilog were also run. Results of these tests are included in Table 16.

Electrical survey measurements on the five wells with millout completions were run principally on an experimental basis. The results as shown in Table 16 are incomplete.

Saraband and Epilog computer analysis minimally require two porosity logging devices--preferably the Compensated Density, Compensated Neutron, and a deep induction Rt device with a Gamma-Ray or S.P. log. Epilog requires Compensated Density, Compensated Neutron or an acoustic porosity. Shallow investigation tools which give Rxo data help to refine these computer log data.

The S.P. and Gamma-Ray are statistically normalized to the neutron-density data for a water-wet sand, for the purpose of establishing clay characteristics when the neutron-density data are affected by hydrocarbon or hole conditions. The Sonic or Acoustic Log serves a somewhat similar purpose as the density in Epilog, but is primarily for the purpose of getting a better porosity when hole quality is poor. It, too, is normalized by statistical processes used in the neutron-density program.

The Rxo measurements, Micro-SFL and Microlateralog, are primarily useful in the quantification of residual oil in the vicinity of the bore-hole. This quantification is most important to making the correct adjustment to neutron-density when hydrocarbon is present. This method is particularly effective when correct data exist on the water resistivities involved. The resulting saturations should more nearly reflect the remaining oil in place in this near-hole region.

The Microlog provided the best sand count and is in good agreement with the core. The Microlog from T-103-Rd, together with previously run Micrologs from other wells in the area, resulted in an increased sand count for each of the wells in the pilot area. Average net sand thickness was increased from 54 to 58 feet. The former counting method had resulted in removing too much shale from the HX_a sand, the reason being that the "shales" are not a continuous homogeneous shale as seen on the electric log but contain interstratified thin sands and shales which are detected in the cores and microloge devices.

Cased-Hole Logs

Cased-hole logs and analyses were run and computed for mill-out completions T-103 and FT-2 by Dresser Atlas. In T-103-Rd, the Dresser Atlas (NLL and C/O) and Schlumberger's (TDT) cased-hole logs were run.

The TDT Cased Reservoir Analysis, as finally presented, represents a stand-alone analysis. It is less quantitative than Saraband; however, the purpose intended was to provide an illustration that TDT could be effectively used in old cased wells to effect a good indication of ROS conditions.

The Epilog analysis processed by Dresser Atlas reports three oil saturation values based on a single porosity value. The oil values are based on (1) the Neutron Lifetime Log, (2) Rt obtained from the Induction Log, and (3) the Carbon/Oxygen Log. The original evaluations received from Dresser Atlas were marked "experimental" because of the interpretive concepts used.

Applicability of the NLL and TDT for estimation of oil saturation following the Micellar-Polymer flood is doubtful. This is because most, if not all, of the formation water (approximately 30,000 mg/1 TDS) will be replaced by fresh water (or micellar slug).

Each of these logs is dependent on measurements of water saturation and oil saturation being calculated by difference. Conversely, the Carbon/Oxygen Log is designed to measure oil saturation directly and salinity of water in the formation has little effect on the results.

Figure 14 is included to show the analyses for the three computed logs for Well T-103-Rd. The Epilog presents oil and water saturation values based on three logging tools. These are the Neutron Lifetime Log (NLL), the Carbon/Oxygen Log (C/O), and the deep induction resistivity (Rt) obtained from open-hole log. The porosity as calculated from the Neutron log is the same for all three saturation determinations. Oil saturation is 26.1 percent for the NLL, 32.6 percent for the C/O, and 32.9 percent for the Rt. For the constant porosity of 29.0 percent, these saturation values equate to 587 and 733 barrels per acre-foot for the NLL and the C/O logs, respectively and 740 barrels per acre-foot for the Rt. The Saraband values for this well are porosity 29 percent, oil saturation 41 percent and oil content 918 barrels per acre-foot.

Saraband Graphic Logs

The Saraband graphic logs as reprocessed August 20, 1980, for the six surface redrills are shown in Figure 15. Average values for porosity, oil saturation, and clay content as percent of bulk volume are shown to the right of each. Porosity varies from a low of 27.0 percent for FT-3 to a high of 29.6 percent for T-104. The average for the recomputed logs is 28.1 percent. The oil saturation values vary from 33.6 percent for FT-1 to 40.8 percent for T-103-Rd. The calculated clay content by well varies from 10.1 percent to 16.6 percent. When only 66 percent of the Saraband determinations are used, the clay content averages 6 percent.

Figure 16 is included to show the Bulk Volume Analysis portion of the six Saraband graphic logs covering approximately 1,400 feet of logged interval. This covers the approximate depth interval from 1,600 to 3,000 feet in each of the six wells. The electrical log markers show the tops of the individual sands for each well. The Tar zone ("S" marker) is the shallowest oil-productive formation in the Wilmington Field. The apparent non-alignment of electric log markers is due to distortion from directional drilling.

In the June 1979 and August 1980, recalculation of the Sarabands, only the HXa section was normalized inasmuch as an attempted histogram of the total well interval was inconclusive. Reasonable data agreement was obtained among the six wells involved, but the use of a slightly gas-saturated sand for a 100 percent water-wet sand would indicate a lower Ro is needed. The importance of geologic variation with geographic position makes it imperative to use spatial normalization proceedings and not simple conclusions based on "a formation." However, only ten acres of surface area are involved, and major sand parameters should be similar.

The results of the reprocessed runs and the initial service runs are summarized below:

	Recomputed Values, August 1980			Initial Service Computations		
Well	Porosity (%)	Oil Sat. (%)	B/A-Ft	Porosity (%)	Oil Sat. (%)	B/A-Ft
Saraband						
FT-1	28.2	33.6	735	27.8	35	755
FT-3	27.0	39.5	827	27.5	38	811
T-101	26.8	40.0	832	26.0	37	746
T-102	28.2	34.6	757	30.3	37	870
T-103-Rd	29.0	40.8	918	24.6	35	668
T-104	29.6	36.1	829	28.1	40	872
Average	28.1	37.4	815	27.4	37	787

(Continued following page)

	Recomputed Values, August 1980			Initial Service Computations		
Well	Porosity (%)	Oil Sat. (%)	B/A-Ft	Porosity (%)	Oil Sat. (%)	B/A-Ft
Cased-Hole Logs						
T-103-Rd:						
Epilog	29.0	26.1 (NLL)	587			
		32.9 (Rt)	740			
		32.6 (C/O)	733			
TDT	23.1	46	824			
T-103:						
Epilog	27.5	29 (NLL)	619	27.0	43 (NLL)	901
		33 (Rt)	704		60 (Rt)	1257
		39 (C/O)	832		10 (C/O)	209
FT-2:						
Epilog	28.8	36 (NLL)	804	24.0	33 (NLL)	614
		26 (Rt)	581		26 (Rt)	484
		32 (C/O)	715		19 (C/O)	354

The Saraband printouts were manually reviewed and screened for the purpose of trying to eliminate values believed to be unfairly influenced by adjacent shale stringers. This resulted in the following:

Well	Porosity (%)	Oil Sat. (%)	B/A Ft.	Percent Clay	% Values Excluded
FT-1	28.8	34.3	766	8.	26
FT-3	29.7	40.1	923	11.	32
T-101	27.7	39.3	845	15.	25
T-102	29.7	34.7	800	8.	33
T-103-Rd	31.0	42.0	1010	6.	34
T-104	31.1	35.4	854	8.	29
Average	29.7	37.6	866	9.	30

In summary these data show a surprisingly low deviation of Saraband-derived values going from the initial service runs, to the final normalized machine runs to those excluding 30 percent of all values reported for net pay. This is illustrated as follows by comparing the two sets of values for August 1980 with the initial service runs.

	Ratio to Initial Processing	
	8/80 As Reported	8/80 Excluding 30% of Values
Porosity	28.1/27.4 = 1.026	29.7/27.4 = 1.084
Oil Saturation %	37.4/37 = 1.011	37.6/37 = 1.016
Oil Content B/A Ft.	815/787 = 1.036	866/787 = 1.100

In the above comparison, change of porosity had little effect on oil saturation percent but did have on the calculated oil content.

Based upon the limited number of cased hole logs available for this study, it appears that the reliability of estimating residual oil saturation is much less than with open hole logging.

Oil Content From Electrical Logs Versus Core Analysis

The following tabulation is a comparison of oil content between the electrical log values as reported in August 1980 using all Saraband reported values and all of the core-derived values.

	Reprocessed Saraband Values			Core Analyses Values Adjusted to 1600 psi Overburden & Reservoir Oil		
Well	Porosity (%)	Oil Sat. (%)	B/A Ft.	Porosity (%)	Oil Sat. (%)	B/A Ft.
FT-1	28.2	33.6	735	28.2	34.8 1/	761
T-102	28.2	34.6	757	27.2	35.3 2/	745
T-103-Rd	29.0	40.8	918	29.5	34.7 3/	794
T-104	29.6	36.1	829	29.6	30.0	689
Avg.4 Wells	28.8	36.3	810	28.6	33.7	747
Avg.6 Wells	28.1	37.4	815			

1/ Laboratory residual oil after waterflood averaged 34.4% for 28.2% porosity.

2/ Laboratory residual oil after waterflood averaged 35.5% for 27.2% porosity.

3/ Laboratory residual oil after waterflood averaged 32.1% for 29.5% porosity.

The core oil saturation adjusted to the porosity values for wet compaction at 1600 psi is in close agreement with laboratory waterflood residual oil values.

The close agreement between the porosity determined on wet samples under 1600 psi confining pressure and the Saraband porosity after data for all wells had been normalized results in the conclusion that the best average values for the HX_a sand in the micellar-polymer area limited by the deviation shown below are oil content 815 barrels per acre foot, 37.4 percent oil saturation and 28.1 percent porosity. The deviation from these acreage values for the six wells is in the following range:

Value	Probable Percent Variance From Best Average Value
Oil Content	+6.0% to -3.4%
Oil Saturation	+0.5% to -1.1%
Porosity %	+5.7% to -2.25%

RESULTS FROM PARTITIONING TRACER TEST

The single-well tracer test for ROS determination (licensed by Exxon) was performed on Well T-103-Rd during February and March 1979. This work was performed by personnel from Union Oil Scientific and Technology Division and utilized their skid-mounted module for partitioning tracer testing.

Prior to testing, some concern was expressed regarding the amount of fluid drift in the HX_a sand through the pilot area and the consequent effect on the test. The drift rate strongly influences the partitioning tracer test. A high drift rate would have required an ester with a high hydrolysis reaction time; e.g., propyl formate. Initially, it was believed that the drift rate might have been high enough to negate test results.

Accordingly, a drift-rate measurement test was initiated on January 29, 1979. The injection water was tagged with a methanol tracer (for the material balance), and isopropanol was injected to tag the end of the slug. After a shut-in period of about a day, the well was put on production. The fluid was sampled until the concentration-production profile indicated that most of the tracer had been produced. A computer match indicated a drift rate of about 0.8 feet per day. This rate was considered acceptable, and the mini-partitioning tracer test was scheduled.

The mini-test began on February 23, 1979. A 1500-barrel slug was injected at 1500 B/D. The first 375 barrels were tagged with ethyl acetate and methanol. The next 925 barrels contained only methanol. The last 200 barrels were tagged with isopropanol. The nominal tracer concentration was 5000 ppm. The actual concentration was determined by gas chromatography with a 20-minute sampling frequency. An injection profile survey was made. Subsequently, the well was shut in on February 24 for the soak period and a pressure fall-off was recorded.

After a soak period of three days, the well was placed on production at about 1500 B/D, and the produced water was sampled and analyzed every 20 minutes until 2674 barrels had been produced. A production profile survey was made.

Union Research reported that "the results of the mini-test were good; however, it was noted that the reaction rate was only 1.6%/day as compared with the laboratory results of 8%/day. It was determined that one of the possible causes was the low-injection-water temperature of 110°F. It was decided to continue with ethyl acetate as the ester used in the Main PTT. The steps taken to help improve the reaction rate on the main test and thus obtain better results were: (a) increase the injection water temperature to 130°F; (b) shut-in the well for 7 days to give a longer reaction; (c) increase the ethyl acetate injection concentration to 6000 ppm."

The main test was initiated by March 3 after about 2000 barrels of chemical-free water had been injected. After a 2580-barrel slug of chemically-tagged water was injected, the well was shut-in for a 7-days soak period, during which a pressure fall-off test was made. During the soak period an adjacent producer, Well T-100, caused a 10-psi increase in pressure in Well T-103A within one day. This upset of reservoir stability has complicated reservoir matching for the main test. Further simulation of the main test has been postponed, because the results of the mini-test are considered good, and additional time would have been required to investigate other theories.

The conclusions of Union's Exploration and Production Research Division were the following:

1. The residual oil saturation in Well T-103-Rd in the Wilmington Field is 39% ± 2%.

2. Unknown factors caused some reservoir parameters to change between the mini-partitioning tracer test and the main partitioning tracer test, thus causing anomalies in the returning chemical concentration curves of the main PTT.

3. A drift rate of 0.8 ft/D was determined from the data.

4. This well would be a good candidate for ROS after an enhanced recovery process has been used to sweep the oil from this area.

The 39% ± 2% oil saturation is in good agreement with the 40.8% value indicated by the reprocessed Saraband log using all values on the computerized printout.

CONCLUSIONS

Several conclusions can be drawn from Phase 1 of this Residual Oil Project. While the study relates only to the Micellar-Polymer Pilot Area (HX_a sand in Upper Terminal Fault Block VB), the findings are applicable to other sands in the Wilmington Field. Some of the findings are pertinent to other unconsolidated oil sand reservoirs and might apply to many sandstones containing clays in their matrixes. The most important results of this study follow:

1. The estimated average residual oil content of the HX_a sand in the pilot area was 815 barrels per acre-foot within the limits of 790 to 870 barrels per acre foot. This estimate relates to (1) a porosity of 28.1 percent and oil saturation of 37.4 percent for Saraband logs from six wells.

2. Core oil saturation adjusted to wet compacted porosity value under 1600 psi confining pressure was within 1 to 6 porosity percent of the oil saturation value from electrical log analysis. The fact that these values are somewhat less than those from the electrical logs probably

is due to loss of oil by pressure reduction from the reservoir to atmospheric.

3. Single well tracer survey on T-103-Rd indicated an oil saturation of 39 percent ±2 percent for whatever the porosity might be. Electrical log derived values were 40.8 percent oil saturation and 920 barrels per acre foot for 29 percent porosity.

4. Cased-hole log analysis for three wells by one set of three methods and for one well with another method do not appear to provide as consistent values for oil content as the open-hole logs. The recomputed Neutron Lifetime and Carbon/Oxygen logs for three wells and the thermal-decay time log for one well yielded oil content values that are ±15 percent of the oil content from open-hole logs.

5. These cased-hole logs may not have applicability in tracking reduction of oil saturation in many tertiary projects because of the widespread use of fresh water. It also appears that sensitivity for oil content needs to be improved.

6. Reprocessing of all six Saraband logs by one specialized analyst, having the advantage of fine-tuning the normalization of data, resulted in some change in values from well to well. However, the change in overall average oil content was small.

7. Conventional core analyses of this unconsolidated sand when obtained with low confining pressure are of little value. To achieve meaningful results, porosity and permeability of unconsolidated sands must be run under confining pressure equivalent to the net overburden load and the samples need to be compacted wet. Values for three different loading

pressures are desirable. In the 1600 to 2000 psi range, porosity of the wet samples, was approximately 92 percent of that for dry compaction.

8. Adsorbed water tests on samples from T-103-Rd indicate an average water content in the clay minerals of 0.0166 ml per ml of grain volume. The loss of adsorbed water--when these samples were subjected to sufficient heat to dehydrate the clay minerals--reduced the effective porosity by about one porosity percent. Either soxhlet extraction with a solvent boiling at 230°F or drying in a convection oven may result in loss of adsorbed water.

9. Special care in laboratory procedures is required to avoid loss of adsorbed water prior to measurement of porosity in sands containing clay minerals. Such loss results in an error in determination of core porosity.

10. The extensive laboratory testing of the core from T-103-Rd illustrates a much wider range of porosity values than hoped for between the helium grain value and helium pore volume compared with liquid-measured pore volume and bulk volumes.

11. Excellent core recovery can be obtained from an unconsolidated sand similar to HX_a using a plastic-sleeved core barrel provided the coring company's personnel are experienced with unconsolidated formations and that core runs are 6 feet or less.

12. A satisfactory method of handling the core after it is removed from the barrel is to cut the plastic sleeve into 3-foot lengths, seal each end, and quick-freeze the core on site before transporting the tubes to the laboratory. The tubes of core should be kept in a deep-freeze unit except

when taking samples for analysis. Unless disk samples are required for laboratory displacement tests, core should be slabbed along one side, the slab set in toolstone, and then color photographed under both incandescent and ultraviolet light.

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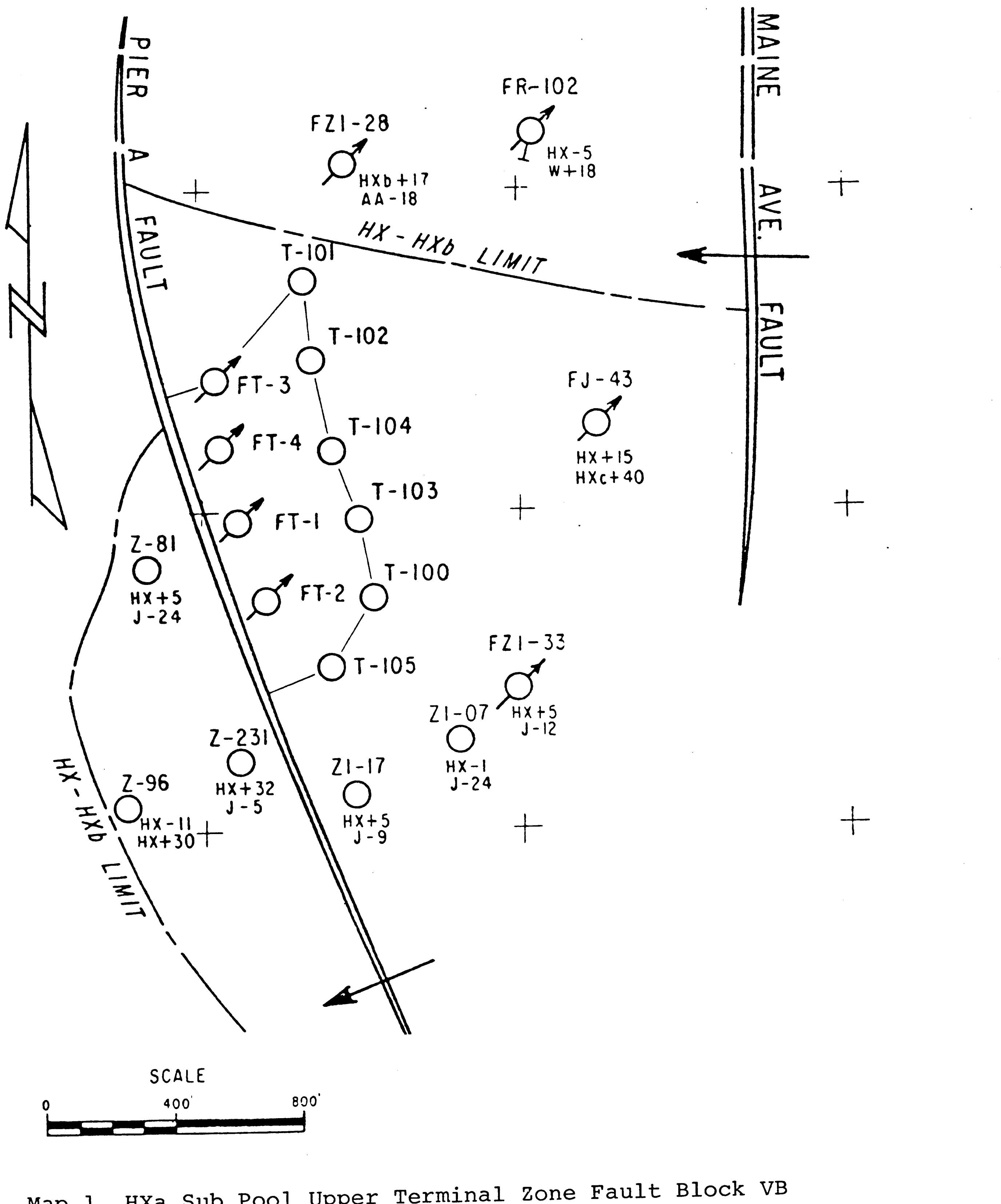


Map 1 HXa Sub Pool Upper Terminal Zone Fault Block VB
(Wilmington Oil Field)

TABLE 1

AVERAGE CORE ANALYSIS BY WELLS

Routine Core Analysis

Well No.	Month Tested	No. Samples	Sleeve Press psi	Porosity % He	Porosity % Wet	Perm md	Liquid Saturation % Oil	Liquid Saturation % Water	Liquid Saturation % Total	Grain Density g/cc
FT-1	7/77	14A	90	39.6		835	21.0	67.0	88.0	2.691
	9/77	14B	0		40.8	802	21.8	60.5	82.3	2.702
		57 1/	0	42.3 1/			15.6	58.0	73.6	2.658 2/
T-102	3/78	5	750	32.1		510	26.4	68.6	95.1	2.664
		16 1/	0	40.9 1/			17.9	51.9	69.8	
T-104	10/78	7	0		40.6		17.4	27.4	44.8	2.714
	10/78	7A		37.7		648				
T-103 Rd	12/78	43A	200		41.8	486	19.3	45.9	65.2	2.667
	12/78	43A	200	39.0		486	21.1	52.1	73.2	
	1/79	45B	1600 4/		35.2					2.68 3/
	1/79	45B	1600 4/		34.5					
	1/79	45B	1600 4/		33.9					
	2/79	8C								
	2/79									
	2/79									
	5/79									

Porosity and Permeability @ Different Confining Pressures, psi

Well No.	No. Samples	Initial Por, % psi	Initial Por, % He	Initial Por, % Wet	350 psi Por	350 psi Perm	800 psi Por	800 psi Perm	1400 psi Por	1400 psi Perm	1600 psi Por	1600 psi Perm	2000 psi Por	2000 psi Perm
FT-1	14B dry	350	38.2		38.2	802	36.0	634			34.1	469	33.0	386
	57 wet								30.2					
T-102	5 dry	750	32.1								30.5	410		
	5A dry	350	33.5		33.5	612	31.3	505			29.2	383	28.2	333
	16 wet								29.2					
T-104	7 wet	0		40.6							30.8			
	7 dry				37.7	648	35.9	478			33.7	344	32.9	315
T-103 Rd	43A dry	200	39.0								33.1			
	8A dry	200	38.2								33.4			
	8C dry	200	37.4		36.5	862	35.0	667			33.4	501	32.7	429
	8D wet 5/	0		39.4	36.1		33.8				32.1		30.8	
	8D wet 6/	0	38.2		34.7		32.4				30.5		29.2	
	6E wet	1600									30.7			

1/ Frozen disc core samples 12.5 cm diameter x 5 cm. Average bulk volume 620.7 cc for FT-1 and 634.0 cc for T-102. Porosity calculated from diameter and thickness of frozen sample less grain volume from dry weight and grain density. Porosity at 1400 psi based on liquid pore volume and grain volume.

2/ 31 samples.

3/ 43 samples.

4/ Samples taken from triaxial pressure cell, extracted, dried, helium grain volume measured and then saturated with brine. Porosity determined by the three following methods:
(a) Liquid pore volume and Archimedes bulk volume
(b) Liquid pore volume and helium grain volume
(c) Helium grain volume and Archimedes bulk volume

5/ Initial porosity determined by liquid pore volume and helium grain volume.

6/ Initial porosity determined by helium pore volume and helium grain volume before saturating with brine.

NOTE: All porosity values are as reported and not corrected for loss of adsorbed clay water. The five duplicate samples for T-102 were the only ones dried in a controlled humidity oven.

TABLE 2

FT-1 CORE ANALYSIS BY PETROLEUM TESTING SERVICE
(5" I.D. PLASTIC SLEEVE CORED JULY 1977, ANALYZED JULY & SEPTEMBER 1977)

Depth Feet	Porosity Percent Helium 1/	Porosity Percent Liquid 2/	Permeability Md	Saturation % Pore Space Oil	Saturation % Pore Space Water	Saturation % Pore Space Total	Absolute Density Sand Grain gm/cc	Calculated Grain Density gm/cc	Overburden Pressure @ 350 psi Helium Porosity Percent	@ 350 psi Air Perm md	@ 800 psi Helium Porosity Percent	@ 800 psi Air Perm md	@ 1600 psi Helium Porosity Percent	@ 1600 psi Air Perm md	@ 2000 psi Helium Porosity Percent	@ 2000 psi Ai Per mc
2977' 1"		43.9		29.4	54.9	84.3	2.709		41.0	1070	38.1	789	35.1	546	34.0	38
*2978'10"	42.9		823	7.4	74.0	81.4	2.683	2.68								
2979' 1"		43.7		17.6	74.6	92.2	2.712		40.6	1110	37.8	814	34.9	609	33.6	45
*2981' 9"	41.4		677	22.8	64.4	87.2	2.674	2.67								
2987' 1"		42.7		17.8	63.5	81.3	2.693		39.2	569	36.7	402	34.1	318	32.9	25
*2987' 7"	41.5		898	9.6	80.9	90.5	2.708	2.68								
2990' 1"		37.8		25.2	63.6	88.8	2.719		36.2	908	34.1	803	32.9	652	32.7	57
*2900' 9"	37.6		580	24.5	65.8	90.3	2.670									
2991' 1"		40.1		22.6	60.8	83.4	2.710		37.2	518	35.4	405	34.2	330	33.0	32
*2993' 7"	39.5		482	26.9	61.9	88.8	2.686	2.66								
2994' 1"		39.5		25.0	48.7	73.7	2.723		37.9	575	36.2	490	34.8	396	33.8	35
*2996' 7"	44.1		846	19.1	78.2	97.3	2.694	2.68								
2997' 1"		43.3		21.0	57.3	78.3	2.714		42.9	1340	41.4	1110	38.3	791	37.2	63
*2997' 8"	42.9		1380	23.9	62.3	86.2	2.693									
2998' 1"		43.0		27.7	52.4	80.1	2.717		41.1	1620	38.5	1340	36.1	957	35.0	76
*3000' 9"	37.4		526	32.1	55.8	87.9	2.680	2.68								
3002' 1"		39.0		30.2	38.7	68.9	2.702		35.5	1200	33.6	890	31.5	578	30.3	50
*3003' 3"	36.8		1890	31.4	54.2	85.6	2.687	2.69								
3003' 6"		35.7		30.9	47.7	78.6	2.688		34.0	955	32.3	870	31.3	703	30.3	61
*3006' 3"	38.8		872	25.8	57.5	83.3	2.684									
3009' 5"		37.3		13.9	75.7	89.6	2.718		34.3	413	32.6	320	31.0	209	38.9	18
*3010' 5"	38.6		330	11.3	80.0	91.3	2.690	2.67								
3011' 1"		42.5		4.3	80.8	85.1	2.567		37.9	134	35.5	77	34.4	50	32.8	4
*3013' 5"	37.6		324	5.7	83.7	89.4	2.704	2.68								
3014' 1"		42.1		26.2	55.6	81.8	2.706		37.7	657	35.9	460	34.2	358	33.2	24
3017' 1"		40.9		13.3	64.8	78.1	2.753		38.9	158	36.5	105	34.6	69	33.9	6
*3017' 4"	41.1		317	17.6	68.5	86.1	2.734	2.71								
*3019' 5"	33.8		1750	36.2	50.5	86.7	2.690	2.69								
Avg Sept '77		40.8	802	21.8	60.5	82.3	2.702		38.2	802	36.0	634	34.1	469	33.0	38
*Avg July tests	39.6		835	21.0	67.	88.0	2.691	2.68								
Avg 28 sples		40.2	818	21.4	63.8	85.2	2.697									

1/ *First set of samples run in July - conventional analysis only using Helium porosity with 90 psi Hassler sleeve pressure.
2/ Second set run in September included helium porosity and permeability at elevated pressures; liquid porosity determined at atmospheric pressure with no prior confining pressure.

TABLE 3

T-102 CORE ANALYSIS BY CORE LABORATORIES, INC., LONG BEACH
(5" I.D. PLASTIC SLEEVE CORED MARCH 1978, ANALYZED MARCH 1978)

Sample No.	Depth Feet	Permeability Millidarcies	Helium Porosity Percent	Core Saturation Percent Pore Volume			Grain Density Gm/cc	Permeability to Air and Helium Porosity Under Overburden Pressure 2/							
								350 psi		800 psi		1600 psi		2000 psi	
				Oil	Water	Total		Md	Percent	Md	Percent	Md	Percent	Md	Percent
1*	3007	761	32.3	38.2	58.8	97.0	2.671					711	31.4		
2	3010	509	32.1	22.2	62.7	84.9	2.660					455	30.2		
3	3033	433	30.2	34.5	74.1	108.6	2.652					282	28.2		
4	3048	300	32.8	19.0	78.5	97.5	2.667					201	31.4		
5	3054	545	33.2	18.3	69.0	87.3	2.669					399	31.4		
Average		510	32.1	26.4	68.6	95.1	2.664					410	30.5		
1A	3007							788	34.1	736	32.6	491	30.3	439	29.7
2A	3010							800	33.0	648	30.8	514	28.9	438	27.6
3A	3033							392	36.2	290	34.0	204	32.1	187	31.2
4A	3048							689	28.7	590	26.2	522	23.5	447	22.3
5A	3054							384	35.4	261	33.1	184	31.0	154	30.3
Average								612	33.5	505	31.3	383	29.2	333	28.2

* Samples first seated in metal jackets using 750 psi triaxial pressure. Oil and water content by Dean-Stark toluene distillation. Porosity by helium gas expansion at 750 and 1600 psi after samples dried in constant humidity oven at 50% relative humidity to assure that two layers of water molecules were retained on any clay minerals present.

2/ Triaxial loading. Samples compacted dry starting with 350 psi triaxial loading.

TABLE 4

T-104 CORE ANALYSIS BY PETROLEUM TESTING SERVICE
(5" I.D. PLASTIC SLEEVE CORED MARCH 1978 ANALYZED OCTOBER 1978)

Sample No.	Depth Feet	Liquid Porosity Percent 1/	Core Saturation Percent of Pore Volume			Absolute Grain Density gm/cc	Permeability and Porosity Under Overburden Pressure							
							350 psi		800 psi		1600 psi		2000 psi	
			Oil	Water	Total		Md	Percent	Md	Percent	Md	Percent	Md	Percent
1	2970' 5"	41.9	13.4	27.3	40.7	2.714						32.7*		
2	2979' 9"	40.9	11.5	26.1	37.6	2.709						27.5*		
3	2982'10"	45.9	28.0	27.8	55.8	2.725						33.3*		
4	2987' 3"	41.9	9.4	23.6	33.0	2.690						30.1*		
5	2990'11"	39.5	20.7	26.4	47.1	2.707						31.3*		
6	2993' 6"	36.8	24.8	23.9	48.7	2.705						31.0*		
7	2996' 8"	37.2	14.3	36.8	51.1	2.748						30.0*		
Average		40.6	17.4	27.4	44.9	2.714						30.8*		
		Helium Por, % (@ 300 psi)												
1A	2970' 5"	40.4					837	40.4	599	37.9	418	35.8	364	35.1
2A	2979' 9"	36.8					416	36.8	228	34.1	124	31.4	106	30.3
3A	2982'10"	40.6					503	40.6	367	39.8	247	37.1	234	36.0
4A	2987' 3"	38.5					1140	38.5	862	35.9	634	33.6	574	32.6
5A	2990'11"	37.4					597	37.4	393	36.5	317	34.3	303	33.4
6A	2993' 6"	35.6					539	35.6	517	34.2	376	32.2	350	31.6
7A	2996' 8"	34.9					502	34.9	378	33.1	293	31.6	276	31.2
Average		37.7					648	37.7	478	35.9	344	33.7	315	32.9

1/ Liquid porosity determined at zero pressure with no prior confining pressure on sleeved sample.

*Samples compacted wet. "A" samples compacted dry.

TABLE 5

T-103 Rd. DEAN-STARK ANALYSIS OF "A" SAMPLES
COMPARISON OF POROSITY AND SATURATION
BY TWO POROSITY METHODS

Sample No.	Depth, Feet	Permeability, Md @ 200 psi	Grain Density, gm/cc	Porosity, % Archimedes 1/	Core Saturation, % PV, Based on Archimedes BV & HeGV			Porosity, % Helium @ 200 psi 2/	Core Saturation, % PV Based on Helium Pore Volume		
					Oil	Water	Total		Oil	Water	Total
1A	2907-08	NM	2.67	NM	NM	NM	NM	NM	NM	NM	NM
2A	2908-09	290	2.67	41.6	17.9	59.8	77.7	38.2	20.6	68.7	89.3
3A	2909-10	281	2.66	43.7	15.1	43.7	58.8	42.6	15.8	45.7	61.5
4A	2910-11	392	2.64	43.6	17.9	39.1	57.0	39.8	21.0	45.8	66.8
5A	2912-13	947	2.68	43.5	13.2	55.8	69.0	39.7	15.4	65.1	80.5
6A	2913-14	317	2.67	43.0	19.3	31.0	50.3	39.7	22.2	35.6	57.8
7A	2914-15	313	2.64	47.2	13.7	34.2	47.9	41.2	17.5	43.7	61.2
8A	2915-16	453	2.69	41.9	17.9	37.9	55.8	37.4	21.5	45.8	67.3
9A	2916-17	375	2.69	42.3	20.2	41.9	62.1	38.8	23.4	48.2	71.6
10A	2917-18	718	2.65	41.8	14.7	38.6	53.3	34.6	20.0	52.4	72.4
11A	2918-19	392	2.69	43.2	13.0	56.5	69.5	40.4	14.6	63.3	77.9
12A	2919-20	447	2.62	42.3	13.5	56.9	70.4	39.3	15.3	64.5	79.8
13A	2920-21	633	2.65	42.0	15.6	47.0	62.6	40.1	16.8	50.8	67.6
14A	2921-22	175	2.65	42.3	20.3	49.0	69.3	39.7	23.3	54.6	77.9
15A	2922-23	653	2.64	42.7	18.3	39.5	57.8	42.2	18.6	40.4	59.0
16A	2923-24	797	2.70	41.3	15.6	55.3	70.9	38.5	17.5	62.0	79.5
17A	2924-25	435	2.67	42.3	14.4	49.2	63.6	38.9	16.6	56.6	73.2
18A	2925-26	388	2.66	41.5	17.5	57.1	74.6	38.1	20.1	65.8	85.9
19A	2926-27	332	2.66	41.0	18.8	42.7	61.5	38.2	21.1	48.0	69.1
20A	2927-28	333	2.70	44.2	18.2	38.1	56.3	41.1	20.7	43.3	64.0
21A	2928-29	380	2.67	33.2	22.9	55.3	78.2	32.4	24.5	57.1	81.6
22A	2929-30	460	2.67	42.5	19.4	48.6	68.0	37.9	23.6	59.0	82.6
23A	2930-31	736	2.65	41.7	22.5	49.7	72.2	39.3	24.8	54.7	79.5
24A	2931-32	240	2.68	41.7	20.3	52.4	72.7	38.5	23.1	60.0	83.1
25A	2932-33	333	2.67	43.3	11.3	52.6	63.9	36.0	13.5	63.4	76.9
26A	2933-34	985	2.69	40.6	23.3	41.7	65.0	36.9	27.2	48.7	75.9
27A	2934-35	237	2.62	45.7	3.4	73.3	76.7	42.7	3.8	82.7	86.5
28A	2935-36	327	2.70	43.6	18.6	39.8	58.4	39.4	22.0	47.3	69.3
29A	2936-37	755	2.71	43.0	16.2	44.9	61.1	41.0 4/	17.6	48.7	66.3
30A	2937-38	761	2.68	43.5	19.9	41.6	61.5	41.0	22.0	46.0	68.0
31A	2938-39	476	2.65	44.3	20.9	43.7	64.6	42.3	22.6	47.4	70.0
32A 3/	2939-40	2.1	2.72	11.6	33.5	31.3	64.8	NM	NM	NM	NM
33A	2940-41	450	2.70	43.9	21.7	39.2	60.9	39.4	26.1	47.3	73.4
34A	2941-42	425	2.68	43.3	18.2	39.6	57.8	37.7 4/	23.3	50.6	73.9
35A	2942-43	433	2.71	40.3	19.1	47.8	66.9	37.4	21.6	53.9	75.5
36A	2943-44	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM
37A	2944-45	489	2.66	42.9	18.0	37.5	55.5	40.3	20.0	41.7	61.7
38A	2945-46	396	2.68	42.8	18.0	27.6	45.6	40.4	19.8	30.4	50.2
39A	2946-47	732	2.69	40.8	20.3	47.2	67.5	36.0	24.9	58.0	82.9
40A	2947-48	568	2.68	40.7	18.5	41.2	59.7	36.5	22.1	49.1	71.2
41A	2948-49	383	2.65	42.6	19.1	40.2	59.3	41.7	19.8	41.6	61.4
42A	2949-50	926	2.65	43.0	19.9	32.2	52.1	40.7	22.0	35.5	57.5
43A	2950-51	803	2.67	33.7	34.2	54.7	88.9	36.1	30.7	49.2	79.9
44A	2951-52	498	2.66	34.2	33.2	56.4	89.6	35.2	31.9	54.1	86.0
45A	2952-53	299	2.63	43.2	13.4	58.0	71.4	42.7	14.3	59.2	73.5
46A	2953-54	591	2.60	33.5	47.2	49.6	96.8	35.6	43.0	45.2	88.2
Average	2908-54	497	2.67	41.8	18.9	46.2	65.1	39.0	21.1	51.9	73.0

1/ "A" Porosity = (Archimedes BV - Helium GV) ÷ Archimedes BV at zero pressure after setting sleeve @ 200 psi.
2/ "A" Porosity = Helium PV ÷ (HePV + HeGV).
3/ Sample No. 32 excluded from average. It represents a thin streak of limy sand.
4/ Samples No. 29A and 34A, helium porosity measured on duplicate plug due to failure of original plug.

TABLE 6

WELL T-103 Rd. POROSITY, PERMEABILITY AND BULK VOLUME

Sample No.	Depth Feet	Porosity, Percent "A" Samples Archimedes 1/	Porosity "A" Helium @ 200 psi 2/	Porosity "A" Helium @ 1600 psi 2/	Porosity "B" Samples HeGV Arch 3/	Porosity "B" Liquid HeGV 4/	Porosity "B" Liquid Arch 5/	Permeability, md "A" @ 200 psi	Permeability "A" @ 350 psi	Permeability "A" @ 1600 psi	Permeability "B" @ 200 psi	Permeability "B" @ 350 psi	Bulk Volume, ml "A" Archimedes @ 200 psi	Bulk Volume "A" Helium @ 200 psi	Bulk Volume "A" Helium @ 1600 psi	Bulk Volume "B" Archimedes	Bulk Volume "B" Liquid PV +HeGV
1	2907-08	NM	NM	NM	34.7	35.5	36.5	NM	NM	NM	322	267	NM	NM	NM	18.79	19.12
2	2908-09	41.6	38.2	32.7	34.7	35.4	36.3	290	248	146	423	201	20.58	19.46	17.87	20.03	20.36
3	2909-10	43.7	42.6	33.3	32.0	33.5	34.8	281	252	126	195	112	13.81	12.89	11.10	20.06	20.62
4	2910-11	43.6	39.8	34.1	31.8	32.4	33.2	392	351	176	110	51	13.92	13.53	12.35	13.33	13.52
5	2912-13	43.5	39.7	35.5	35.9	36.4	37.2	947	865	433	593	421	20.95	19.65	18.37	20.31	20.57
6	2913-14	43.0	39.7	32.8	35.0	35.7	36.6	317	256	146	784	650	13.59	12.83	11.52	20.76	21.09
7	2914-15	47.2	41.2	32.0	31.3	32.2	32.9	313	270	128	375	267	10.85	9.57	8.28	18.16	18.47
8	2915-16	41.9	37.4	31.2	32.3	33.2	34.2	453	407	272	201	201	22.72	21.09	19.19	18.33	18.66
9	2916-17	42.3	38.8	33.2	31.5	32.3	33.1	375	328	180	403	215	23.76	22.41	20.55	14.50	14.73
10	2917-18	41.8	34.6	33.2	31.8	32.5	33.4	718	610	375	292	292	16.24	14.46	14.15	17.66	17.94
11	2918-19	43.2	40.4	35.0	NM	34.1	34.1	392	317	195	574	574	22.56	20.94	19.17	12.72	NM
12	2919-20	42.3	39.3	33.0	33.1	33.7	32.4	447	366	223	126	126	12.59	11.96	10.84	19.64	19.93
13	2920-21	42.0	40.1	29.7	32.6	33.1	33.9	633	519	261	188	88.9	17.12	16.58	14.12	17.80	18.03
14	2921-22	42.3	39.7	34.4	34.1	33.7	30.8	175	145	90	339	196	16.67	15.96	14.66	15.20	14.04
15	2922-23	42.7	42.2	34.1	32.9	33.4	34.1	653	555	269	284	281	13.15	13.02	11.43	14.50	14.68
16	2923-24	41.3	38.5	34.5	33.9	34.1	34.7	797	693	416	252	178	22.04	21.05	19.75	21.48	21.64
17	2924-25	42.3	38.9	33.8	33.4	33.9	34.7	435	399	258	249	173	20.47	19.32	17.84	16.63	16.85
18	2925-26	41.5	38.1	33.7	33.3	33.7	34.5	388	343	196	530	196	20.95	19.80	18.49	18.70	18.92
19	2926-27	41.0	38.2	32.5	31.4	32.9	34.2	332	298	177	447	262	21.42	20.45	18.72	20.22	20.77
20	2927-28	44.2	41.1	35.3	32.2	32.9	33.7	333	292	158	358	262	20.30	19.21	17.51	17.72	17.99
21	2928-29	33.2	32.4	27.8	NM	35.3	35.3	380	346	254	99	248	18.74	18.56	17.71	17.49	NM
22	2929-30	42.5	37.9	33.0	35.0	34.0	33.9	460	405	258	604	426	24.08	22.28	20.65	15.30	15.14
23	2930-31	41.7	39.3	34.7	NM	37.0	37.0	736	683	412	304	304	16.71	16.07	14.93	15.35	NM
24	2931-32	41.7	38.5	34.3	35.7	36.0	36.7	240	217	143	431	341	24.38	23.10	21.65	22.19	22.40
25	2932-33	43.3	36.0	31.1	33.5	34.2	35.2	333	310	198	169	169	17.24	17.24	16.03	19.20	19.53
26	2933-34	40.6	36.9	32.1	38.1	39.5	40.4	985	936	541	151	151	19.20	18.08	16.79	11.60	11.76
27	2934-35	45.7	42.7	35.9	36.0	36.9	38.1	237	218	100	325	182	17.53	16.62	14.85	20.26	20.68
28	2935-36	43.6	39.4	35.8	34.1	34.5	35.2	327	291	168	306	210	24.36	22.68	21.41	22.16	22.41
29	2936-37	43.0	41.0	35.5	35.8	36.6	37.6	755	740	434	336	229	21.07	20.38	18.62	22.39	22.78
30	2937-38	43.5	41.0	34.1	35.3	35.9	36.8	761	684	418	229	229	17.92	17.18	15.37	17.14	17.41
31	2938-39	44.3	42.3	35.1	36.8	37.8	39.0	476	428	281	278	278	18.09	17.46	15.52	22.15	22.63
32	2939-40 6/	11.6	NM	NM	11.8	12.3	12.5	2.1	1.5	0.7	2.4	2.4	22.86	NM	NM	17.78	17.91
33	2940-41	43.9	39.4	33.8	36.0	35.9	36.4	450	401	264	887	524	24.27	22.45	20.55	21.98	22.07
34	2941-42	43.3	37.7	33.1	34.9	35.5	36.4	425	391	219	889	566	19.30	18.33	17.05	18.12	18.39
35	2942-43	40.3	37.4	33.2	35.4	35.8	36.6	433	327	223	792	463	23.78	22.69	21.27	18.36	18.58
36	2943-44	NM	NM	NM	30.9	31.3	32.8	797	733	369	374	374	NM	NM	NM	15.28	15.45
37	2944-45	42.9	40.3	35.7	30.7	31.0	31.6	489	450	258	341	341	21.09	20.17	18.73	16.85	17.00
38	2945-46	42.8	40.4	32.3	32.8	33.1	33.8	396	324	166	796	491	13.86	13.32	11.71	21.20	21.41
39	2946-47	40.8	36.0	29.6	31.6	32.3	33.2	732	659	445	650	650	25.35	23.41	21.28	14.56	14.79
40	2947-48	40.7	36.5	31.3	33.5	34.2	35.1	568	523	254	655	655	20.16	18.84	17.40	15.00	15.24
41	2948-49	42.6	41.7	34.9	34.6	35.1	35.8	383	326	178	722	510	11.68	11.52	10.31	19.69	19.93
42	2949-50	43.0	40.7	34.1	34.4	35.8	37.0	926	833	473	848	711	12.79	12.27	11.05	12.28	12.60
43	2950-51	33.7	36.1	28.7	33.2	33.7	34.5	803	683	451	861	655	15.71	16.29	14.60	15.11	15.31
44	2951-52	34.2	35.2	31.2	34.1	34.3	35.0	498	439	290	608	608	14.55	14.76	13.91	13.18	13.29
45	2952-53	43.2	42.7	33.5	36.2	36.6	37.3	299	270	131	395	395	10.61	10.51	9.063	12.76	12.89
46	2953-54	33.5	35.6	30.2	36.1	36.8	37.8	NM	NM	NM	369	369	16.85	17.40	16.06	12.12	12.33
Average		41.8	39.0	33.1	33.9	34.5	35.2	501	445	259	433	335	18.44	17.6	16.10	17.68 7/	17.90 7/

1/ "A" porosity = (Archimedes BV - Helium GV) ÷ Archimedes BV after 200 psi sleeve pressure.
2/ "A" porosity = Helium PV ÷ (He PV + HeGV).
3/ "B" porosity = (Archimedes BV - HeGV) ÷ Archimedes BV. 42 samples after 200 psi sleeve pressure.
4/ "B" porosity = Liquid PV ÷ (Liquid PV + HeGV). 45 samples after 200 psi sleeve pressure.
5/ "B" porosity = Liquid PV ÷ Archimedes BV. 45 samples
6/ Sample No. 32 excluded from average. It represents a thin streak of limy sand.
7/ Average 42 "B" samples excludes samples No. 11, 21 and 23 and 32.

NOTE: "A" - Fresh samples set @ 200 psi sleeve pressure.
"B" - Fresh samples compacted @ 1600 psi removed from triaxial pressure cell, extracted, dried, helium grain volume measured and then saturated with brine under vacuum.

TABLE 7

WELL T-103-RD COMPARISON OF HELIUM POROSITY, PERCENT FOR "C" SET OF SAMPLES WITH DUPLICATE "A" SAMPLES

Sample No.	Depth Feet	HeØ @ 200 psi		HeØ @ 1600 psi	
		A	C	A	C
2	2908-09	38.2	37.8	32.7	33.0
7	2914-15	41.2	41.2	32.0	36.3
11	2918-19	40.4	37.5	35.0	33.4
16	2923-24	38.5	37.1	34.5	32.8
23	2930-31	39.3	37.4	34.7	33.2
30	2937-38	41.0	37.8	34.1	34.6
37	2944-45	40.3	34.8	35.7	31.5
43	2950-51	36.1	35.4	28.7	32.0
Average (8)		39.4	37.4	33.4	33.4

TABLE 8

T-103 Rd. LIQUID COMPACTION "D" SAMPLES

Sample No.	Depth Feet	Overburden Sleeve Press psi	Grain Volume cc	Liquid Pore Vol. cc	Reduction in Pore Vol. cc	Liquid Porosity Percent	Helium Pore Vol. cc 1/	Helium Porosity Percent
2D	2908-09	0	13.698	7.924		36.7	7.575	35.6
		350		7.624	0.30	35.8	7.275	34.7
		800		7.014	0.910	33.9	6.665	32.7
		1600		6.604	1.32	32.5	6.255	31.3
		2000		6.394	1.53	31.8	6.045	30.6
7D	2914-15	0	10.348	7.713		42.7	7.265	41.2
		350		6.643	1.070	39.1	6.195	37.4
		800		6.073	1.640	37.0	5.625	35.2
		1600		5.303	2.410	33.9	4.855	31.9
		2000		4.933	2.780	32.3	4.485	30.2
11D	2918-19	0	8.809	5.568		38.7	5.425	38.1
		350		4.775	0.793	35.2	4.632	34.5
		800		4.145	1.423	32.0	4.002	31.2
		1600		3.805	1.763	30.2	3.662	29.4
		2000		3.645	1.923	29.3	3.502	28.4
16D	2923-24	0	12.639	8.105		39.1	7.695	37.8
		350		7.045	1.060	35.8	6.635	34.4
		800		6.405	1.700	33.6	5.995	32.2
		1600		5.756	2.349	31.3	5.346	29.7
		2000		5.455	2.650	30.1	5.045	28.5
23D	2930-31	0	9.577	7.762		44.8	6.875	41.8
		350		5.962	1.800	38.4	5.075	34.6
		800		5.352	2.410	35.8	4.465	31.8
		1600		5.062	2.700	34.6	4.175	30.4
		2000		4.930	2.832	34.0	4.043	29.7
30D	2937-38	0	11.50	7.591		39.8	7.090	38.1
		350		7.341	0.250	39.0	6.840	37.3
		800		6.741	0.850	37.0	6.240	35.2
		1600		6.341	1.250	35.5	5.840	33.7
		2000		5.491	2.100	32.3	4.990	30.3
37D	2944-45	0	8.197	4.683		36.4	4.675	36.3
		350		3.873	0.810	32.1	3.865	32.0
		800		3.483	1.200	29.8	3.475	29.8
		1600		3.143	1.540	27.7	3.135	27.7
		2000		3.073	1.610	27.3	3.065	27.2
43D	2950-51	0	10.069	5.946		37.1	5.825	36.6
		350		5.046	0.900	33.4	4.925	32.8
		800		4.676	1.270	31.7	4.555	31.1
		1600		4.458	1.488	30.7	4.337	30.1
		2000		4.206	1.740	29.5	4.085	28.9
32D	2939-40	0	22.229	3.478		13.5	3.79	14.6
		350		3.028	0.450	12.0	3.34	13.1
		800		2.788	0.690	11.1	3.10	12.2
		1600		2.738	0.740	11.0	3.05	12.1
		2000		2.718	0.760	10.9	3.03	12.0

8 Samples, Avg Gr Vol cc 10.60

Average of 8 Samples: Liquid PV Porosity %	Average of 8 Samples: Helium PV Porosity %	Average Corresp. "A" Samples: Arch	Average Corresp. "A" Samples: He
39.4 2/	38.2 1/	41.9	38.6
36.1	34.7		
33.9 1/	32.4		
32.1 1/	30.5		33.4
30.8	29.2		

1/ At 200 psi sleeve pressure.

2/ At 0 psi after 200 psi sleeve pressure.

TABLE 9

T-103 Rd. SUMMARY OF WATERFLOOD SUSCEPTIBILITY TEST RESULTS

Sample Number	Depth, Feet	Permeability,* Millidarcies	Porosity,** Percent	Initial Conditions: Water Saturation, Percent Pore Space	Initial Conditions: Oil Permeability, Millidarcies	Terminal Conditions: Oil Saturation, Percent Pore Space	Terminal Conditions: Water Permeability, Millidarcies	Oil Recovered: Percent Pore Space	Oil Recovered: Percent Oil in Place
2E	2908-09	128	29.7	36.1	97.2	23.0	21.4	40.9	64.0
7E	2914-15	174	31.6	17.5	158	44.6	45.3	37.9	45.9
11E	2918-19	110	30.8	42.0	93.4	20.9	15.2	37.1	64.0
16E	2923-24	63.5	29.3	39.0	45.2	23.3	5.8	37.7	61.8
23E	2930-31	67.3	32.0	45.1	69.5	24.1	7.6	30.8	56.1
43E	2950-51	246	30.6	17.4	150	45.7	26.9	36.9	44.7
Average		131	30.7	32.8	102	30.3	20.4	36.9	55

Oil-Water viscosity ratio 65:1
*Air permeability determined at 1600 psi overburden pressure.
**Porosity calculated from the grain volume and final saturations from Dean-Stark procedure.

	Prior WFS Tests on 7 Samples Analyzed 12-12-58 and 6-6-61							
Average	560	37.5	26.8	214	27.3	101	45.9	63

Prior WFS tests run with no confining pressure. Average oil-water viscosity ratio 59:1

TABLE 10

WELL T-103-RD FORMATION FACTOR AND RESISTIVITY INDEX DATA

Resistivity of Saturating Brine, Ohm-Meters: 0.233 @ 76°F

Sample No.	350 PSI, Overburden Pressure Air Perm (Md)	Porosity1/ (%)	1600 PSI, Overburden Pressure Formation Factor	Brine Saturation (% Pore Space)	Resistivity Index
10B	292	32.5	9.69	100.0	
				23.5	22.4
16B	178	34.1	10.46	100.0	
				37.2	3.67
22B	426	34.0	10.19	100.0	
				23.0	21.6
27B	182	36.9	9.17	100.0	
				72.1	2.39
28B	210	34.5	8.91	100.0	
				40.9	9.40
33B	524	35.9	8.41	100.0	
				24.5	19.7
34B	566	35.5	8.10	100.0	
				22.9	22.0
45B	395	36.6	9.70	100.0	
				34.8	11.1

1/ Porosity, % = $\frac{\text{Saturation Pore Volume}}{\text{Sat. Pore Volume + Helium Grain Volume}} \times 100$

These are the first run of capillary pressure tests which gave unsatisfactory displacement at the lower pressures because of poor contact with the porous plate. However, the resistivity measurements should be valid for the reported saturation conditions. These capillary pressure and resistivity index tests were run under zero confining pressures. However, the formation factor (i.e. the resistivity of the 100% brine-saturated plug) was run under 1600 psi overburden pressure. Porosity was measured under zero psi confining pressure by saturating the plugs under vacuum.

TABLE 11

WELL T-103-RD AIR-BRINE CAPILLARY PRESSURE DATA

Sample No.	Perm (Md)	Por (%)	Brine Saturation, % Pore Space, @ Press. PSI of: 0.25	0.5	1.0	2.0	4.0	8.0	15	35
3B	112	33.3	100.0	100.0	100.0	95.6	66.4	48.2	39.1	33.0
9B	215	33.8	100.0	100.0	95.7	81.9	51.8	37.2	29.9	28.8
10B	292	32.5	100.0	100.0	98.0	81.2	49.8	34.9	27.5	22.5
16B	178	34.3	100.0	100.0	97.6	92.3	62.7	44.4	35.4	31.5
22B	426	33.4	100.0	100.0	100.0	85.0	53.7	38.1	30.4	25.7
27B	182	37.1	100.0	100.0	100.0	95.5	66.9	48.1	39.9	28.4
28B	210	34.2	100.0	100.0	100.0	96.3	61.1	43.3	35.2	31.3
33B	524	35.3	100.0	100.0	100.0	92.5	50.5	37.1	30.2	27.0
34B	566	35.3	100.0	100.0	96.5	73.9	45.4	32.4	26.1	22.9
45B	395	37.8	100.0	100.0	100.0	93.8	63.4	45.3	36.6	30.7
Avg	310	34.7	100.0	100.0	98.8	88.8	57.2	40.9	33.0	28.2

The last eight plugs are reruns of samples listed in Table 14 listing formation factor and resistivity index data. Capillary pressure tests were rerun due to unsatisfactory test results at low pressures on the previous tests. The difference in the two sets of porosity values is to be expected in this unconsolidated sand. Liquid pore volume was measured under zero confining pressure in both cases.

TABLE 12

T-103 Rd. HELIUM POROSITY AND PERMEABILITY

Sample No.	Depth Feet	Samples Compacted Dry: 200 psi Porosity Percent	200 psi Permeability Millidarcies	350 psi Porosity Percent	350 psi Permeability Millidarcies	800 psi Porosity Percent	800 psi Permeability Millidarcies	1600 psi Porosity Percent	1600 psi Permeability Millidarcies	2000 psi Porosity Percent	2000 psi Permeability Millidarcies
2-C	2908-09	37.8	582	36.7	498	34.8	377	33.0	260	32.4	232
7-C	2914-15	41.2	1975	40.4	1806	38.2	1278	36.3	1016	35.5	846
11-C	2918-19	37.5	884	36.5	714	34.7	502	33.4	373	32.6	332
16-C	2923-24	37.1	632	36.1	545	35.3	409	32.8	289	32.2	234
23-C	2930-31	37.4	417	36.5	387	34.9	319	33.2	254	32.4	228
30-C	2937-38	37.8	755	36.7	724	36.0	556	34.6	395	33.9	316
37-C	2944-45	34.8	1284	34.4	1264	33.0	1011	31.5	775	31.0	667
43-C	2950-51	35.4	1046	34.7	962	33.4	882	32.0	648	31.3	577
Average		37.4	947	36.5	862	35.0	667	33.4	501	32.7	429
32-C	2939-40	14.8	111	14.2	85	13.3	18	12.6	8	12.5	6
		Samples Compacted Wet Starting With Helium Porosity									
2-D	2908-09	35.6		34.7		32.7		31.3		30.6	
7-D	2914-15	41.2		37.4		35.2		31.9		30.2	
11-D	2918-19	38.1		34.5		31.2		29.4		28.4	
16-D	2923-24	37.8		34.4		32.2		29.7		28.5	
23-D	2930-31	41.8		34.6		31.8		30.4		29.7	
30-D	2937-38	38.1		37.3		35.2		33.7		30.3	
37-D	2944-45	36.3		32.0		29.8		27.7		27.2	
43-D	2950-51	36.6		32.8		31.1		30.1		28.9	
Average		38.2		34.7		32.4		30.5		29.2	
32-D	2939-40	14.6		13.1		12.2		12.1		12.0	

TABLE 13

T-103 REDRILL HX_a FORMATION FACTORS
(RUN BY C.L.I. OKLAHOMA CITY, RESISTIVITY OF BRINE, OHM M:0.233 @ 76)

Sample No.	Depth, Feet Core From	Core To	10" Micro Log	0 psi Confining Press After Compacting to 1600 psi 2/ Por %	Fm Factor	1600 psi Confining Press He Por 1/%	Fm Factor	Grain Density gm/cc
1B	2907	2908	2906.2	34.7	4.98		11.90	2.67
2B	2908	2909	2907.	34.7	4.74	31.3	9.32	2.68
3B	2909	2910	2908.	32.0	5.60		12.12	2.66
4B	2910	2911	2909.	31.8	5.60		12.30	2.67
5B	2912	2913	2911.5	35.9	4.70		11.20	2.71
6B	2913	2914	2912.5	35.0	5.65		9.56	2.68
7B	2914	2915	2913.5	31.3	6.17	31.9	11.11	2.67
8B	2915	2916	2914.5	32.3	5.86		8.96	2.65
9B	2916	2917	2915.5	31.5	6.14		10.98	2.66
10B	2917	2918	2916.5	31.8	5.36		9.69	2.72
11B	2918	2919	2917.5	ND	ND	29.4	ND	ND
12B	2919	2920	2918.5	33.1	5.76		8.89	2.68
13B	2920	2921	2919.5	32.6	5.15		10.01	2.68
14B	2921	2922	2920.5	34.1	5.04		9.54	2.64
15B	2922	2923	2921.5	32.9	5.78		10.56	2.67
16B	2923	2924	2922.5	33.9	6.40	29.7	10.46	2.69
17B	2924	2925	2923.5	33.4	4.64		9.42	2.69
18B	2925	2926	2924.5	33.3	5.60		9.51	2.72
19B	2926	2927	2925.5	31.4	6.14		10.27	2.64
20B	2927	2928	2926.5	32.2	6.30		10.19	2.67
21B	2928	2929	2927.5	ND	ND		ND	2.69
22B	2929	2930	2928.5	35.0	6.09		10.19	2.70
23B	2930	2931	2929.5	ND	ND	30.4	ND	2.65
24B	2931	2932	2930.5	35.7	5.64		8.88	2.70
25B	2932	2933	2931.5	33.5	4.49		8.41	2.67
26B	2933	2934	2932.5	38.1	5.18		14.15	2.62
27B	2934	2935	2933.5	36.0	5.02		9.17	2.67
28B	2935	2936	2934.5	34.1	5.47		8.91	2.71
29B	2936	2937	2935.5	35.8	5.12		8.19	2.70
30B	2937	2938	2936.5	35.3	4.69	33.7	7.02	2.70
31B	2938	2939	2937.5	36.8	4.94		8.82	2.74
32B	2939	2940	2938.5	11.8	18.26	11.0	47.15	2.72
33B	2940	2941	2939.5	36.0	5.51		8.41	2.78
34B	2941	2942	2940.5	34.9	5.30		8.10	2.68
35B	2942	2943	2941.5	35.4	5.31		8.35	2.68
36B	2943	2944	2942.5	30.9	6.22		10.01	2.67
37B	2944	2945	2943.5	30.7	5.72	27.7	9.38	2.69
38B	2945	2946	2944.5	32.8	6.03		9.52	2.68
39B	2946	2947	2945.5	31.6	5.20		8.44	2.66
40B	2947	2948	2946.5	33.5	4.62		7.87	2.68
41B	2948	2949	2947.5	34.6	5.33		9.41	2.68
42B	2949	2950	2948.5	34.4	5.62		9.89	2.66
43B	2950	2951	2949.5	33.2	4.59	30.1	8.05	2.67
44B	2951	2952	2950.5	34.1	5.34		9.75	2.66
45B	2952	2953	2951.5	36.2	5.26		9.70	2.68
46B	2953	2954	2952.5	36.1	4.33		8.88	2.68
Average - all samples				33.4	5.70		10.53	2.68

1/ From "D" samples compacted wet starting with Helium porosity. 2/ 43 "B" samples

TABLE 14

FT-1 AND T-102 CORE ANALYSIS BY MARATHON OIL COMPANY

Depth, Feet From	To	No. Samples for Porosity	Sat.	Frozen Samples Diam 12.5 cm Bulk Vol 620 cc Porosity Percent	Oil	Water	Total	1400 psi Overburden Pressure Por, % Sum of Fluids 3/	Porosity Percent Wgt Diff.	Saturation Percent Water After Oil Flood	Oil After Waterflood	Permeability, Millidarcies To Oil @ Residual Wtr	To Water @ Residual Oil
FT-1													
2977	2979	1	0	ND	ND	ND	ND	28.6 1/	29.3 1/	44. 1/	29.2 1/		
2979	2982	4	4	42.8	16.4	54.4	70.8	28.9	30.0	37.0	30.8	47.9	2.9
2991	2994	8	8	41.0	11.3	62.1	73.4	29.7	30.9	40.1	31.0	25.6	3.5
2994	2997	13	13	42.4	16.1	60.0	76.1	31.0	31.6	39.7	30.3	29.2	4.2
2998	3001	10	0					30.1	27.2 2/	ND	ND		
3003	3006	8	8	41.6	16.4	57.0	73.4	29.5	30.2	39.2	29.4	19.6	4.1
3009	3011	2	2	42.0	12.7	58.4	71.1	30.2	31.2	42.9	27.8	31.2	3.2
3011	3014	7	7	45.0	15.9	55.5	71.4	30.0	31.3	38.1	31.8	39.0	4.1
3014	3017	9	9	41.8	14.4	58.7	73.1	30.5	31.6	38.5	31.8	57.5	5.0
3017	3020	6	6	41.7	21.9	52.8	74.7	30.6	31.5	39.9	36.0	76.3	3.8
Wtd Avg/ft		67	57	42.3	15.7	57.3	73.0	30.0	30.5	39.6	31.1	41.2	3.9

1/ Sample No. 695 was thoroughly cleaned, porosity determined, resaturated with brine, flooded with oil and then waterflooded.

2/ Two samples No. 837 and 838.

3/ Used by MOC in calculation of all saturation (%) calculations.

Depth, Feet From	To	No. Samples for Porosity	Sat.	Porosity Percent	Oil	Water	Total	Por, % Sum of Fluids	Porosity Percent Wgt Diff.	Water After Oil Flood	Oil After Waterflood	To Oil @ Residual Wtr	To Water @ Residual Oil
T-102													
3005	3008	2	2	41.4	21.8	48.2	70.0	29.7	30.3	33.1	36.6	128.	6.0
3008	3011	5	5	40.5	16.8	50.1	66.9	28.0	28.7	34.3	33.2	124.	23.7
3033	3035	6	6	43.1	17.2	53.3	70.5	30.6	31.7	37.7	30.6	69.8	4.6
3046	3049	3	3	36.7	18.8	54.7	73.5	28.3	28.9	37.8	30.5	68.9	4.4
Wtd Avg/ft		16	16	40.2	18.8	51.4	70.2	29.0	29.7	35.6	32.9	100.	10.1

NOTE: Temperature of solvent during extraction in excess of that required for samples to retain bound water, which is estimated to average 1.2 porosity percent. Thus, corrected porosity value is 28.8 and 27.8, respectively, for FT-1 and T-102.

TABLE 15

PERMEABILITY AND POROSITY AT DIFFERENT CONFINING PRESSURES
AVERAGE VALUES BY WELLS 1/

Well	No. Samples	Perm to Air, Md Confining Press., psi 350	800	1600	2000
FT-1	14	802	634	469	386
T-102	5	612	505	383	333
T-103-Rd	8C	862	667	501	429
T-104	7	648	478	344	315
Well Avg	34	731	571	424	366

Well	No. Samples	Porosity, Percent Confining Pressure, psi 350	800	1400	1600	2000
SAMPLES COMPACTED DRY						
FT-1	14	37.2 (38.2)	34.9 (36.0)		33.0 (34.1)	31.9 (33.0)
T-102	5A	33.5 (33.5)	31.3 (31.3)		29.2 (29.2)	28.2 (28.2)
	5				30.5 (30.5)	
T-103-Rd	8C	35.4 (36.5)	33.9 (35.0)		32.3 (33.4)	31.6 (32.7)
T-104	7	36.7 (37.7)	34.8 (35.9)		32.6 (33.7)	31.8 (32.9)
Well Avg		35.7 (36.5)	33.7 (34.6)		31.8 (32.8)	30.9 (31.7)
No. Wells		4	4		4	4
No. Samples		34	34		39	39
SAMPLES COMPACTED WET						
FT-1	57			28.8 (30.0)		
T-102	16			27.8 (29.0)		
T-103-Rd	8D	33.6 (34.7)	31.3 (32.4)		29.3 (30.5)	28.0 (29.2)
	6E				29.5 (30.7)	
T-104	7				29.6 (30.8)	
Well Avg		33.6 (34.7)	31.3 (32.4)	28.3 (29.5)	29.5 (30.7)	28.0 (29.2)
No. Wells		1	1	2	2	1
No. Samples		8	8	73	21	8

1/ Porosity values corrected for adsorbed water as determined for 32 samples from T-103-Rd. Values in ( ) are as reported, but are for laboratory procedures which result in loss of adsorbed water. Controlled humidity oven was used for the 5 and 5A samples for T-102.

TABLE 16

SUMMARY OF ELECTRICAL LOG ANALYSIS, HX_a SAND

Well No.	Log	MW Depth (Feet) From	MW Depth (Feet) To	Net Feet of Sand MWD Log	Net Feet of Sand Official VSS 2/	Perm Index	Porosity (Percent)	Oil Sat. (Percent)	From Engineering Printout: Porosity (Percent) Neutron	Porosity (Percent) Density	Rt DIL 4/	VSH (Silt %)	VCL (Clay %)	Grain Density	BHT and Resistivity: Rw @ BHT 3/	BHT Corrected 3/	E Log BHT Max Recorded
SURFACE REDRILLS																	
FT-1	Saraband 1/	2965	3010	46	61	164	28.2	34.	34.9	32.2	2.9	20	10	2.67	.138	137	120
FT-3	Saraband 1/	3062	3125	67	59	202	27.0	40.	40.2	32.7	2.5	26	13	2.69	.133	143	NR
T-101	Saraband 1/	3099	3141	44	59	82	26.8	40.	39.8	32.4	3.1	34	17	2.69	.176	106	123
T-102	Saraband 1/	3008	3050	43	60	140	28.2	35.	36.8	31.3	2.8	21	10	2.68	.166	113	110
T-103-Rd	Saraband 1/	2906	2946	41	54	157	29.0	41.	38.6	31.0	2.8	20	10	2.71	.137	138	119
T-104	Saraband 1/	2969	3030	62	62	213	29.6	36.	38.1	32.7	2.6	20	10	2.68	.139	136	117
Avg (6)	Saraband 1/			50.5	59	160	28.1	38.	38.1	32.1	2.8	24	12	2.69	.148	129	
T-103-Rd	TDT	2905	2939	35	54	104	23.1	45.7				14					
T-103-Rd	Epilog 7/	2904	2937	34	54	125	29.0	(NLL) 26.1 (Rt) 32.9 (C/O) 32.6				14					
MILL-OUT COMPLETIONS																	
FT-2	Epilog 7/	2930	2997	56	60	125	28.8 5/	(NLL) 36. (Rt) 26. (C/O) 32.			2.0 6/		13		.137	138	118
FT-4	DIL	2967	3034	67	58						3.0				.133	142	128
T-100	DA, DIL	2882	2952	70	53						1.9				.133	142	120
T-103	Epilog 7/	2896	2958	54	54	106	27.5 5/	(NLL) 29. (Rt) 33. (C/O) 39.			3.0		15		.137	138	130
T-105	DIL, Densilog	2947	2993	46	53					35.7	2.7				.135	140	NR
Average				59	56										.135	140	

1/ Schlumberger Saraband and Engineering Printout dated 8-20-80.
2/ VSS net feet of sand is revised sand count agreed upon by M. E. Wright and C. E. Monson based on core and microlog correlation from T-103-Rd and microlog from other old wells.
3/ Corrected Rw and corrected BHT from C. E. Monson memo to R. H. Newman dated 8-11-78 based on static bottom hole temperature surveys.
4/ Rt from engineering printout for wells with Saraband and with Epilog. Values for other wells calculated from conductivity curves.
5/ Dresser Atlas Neutron log through casing.
6/ FT-2. In April 1960 Rt = 6.2.
7/ Epilog revised data 6-27-79.

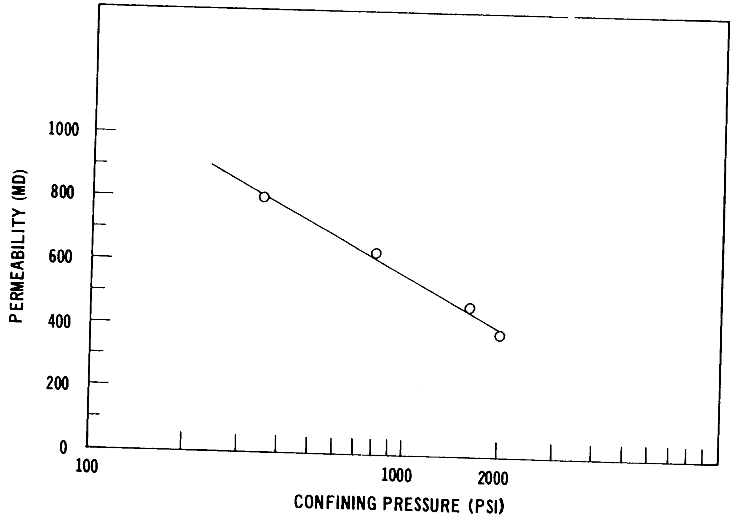


Figure 1-A Effect of Overburden Load on Permeability (FT-1) Compacted Dry

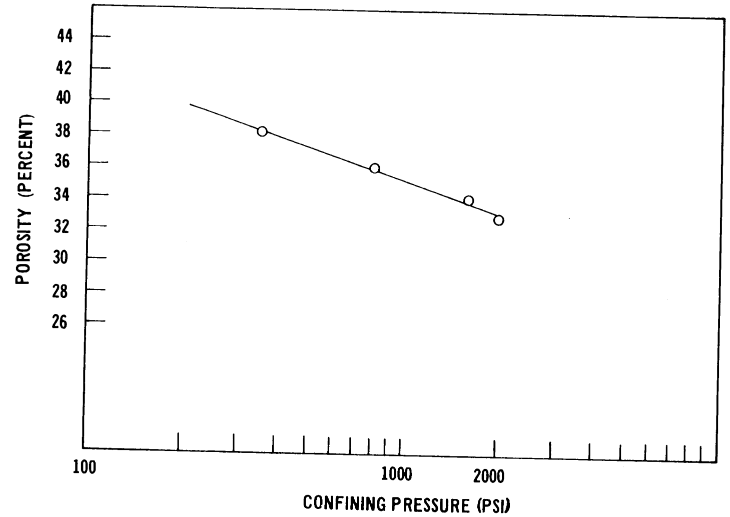


Figure 1-B Effect of Overburden Load on Porosity (FT-1) Compacted Dry

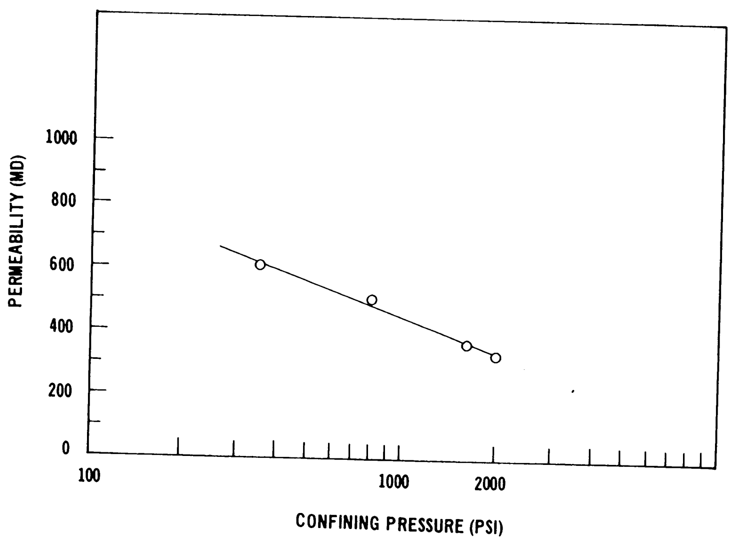


Figure 2-A Effect of Overburden Load on Permeability (T-102) Compacted Dry

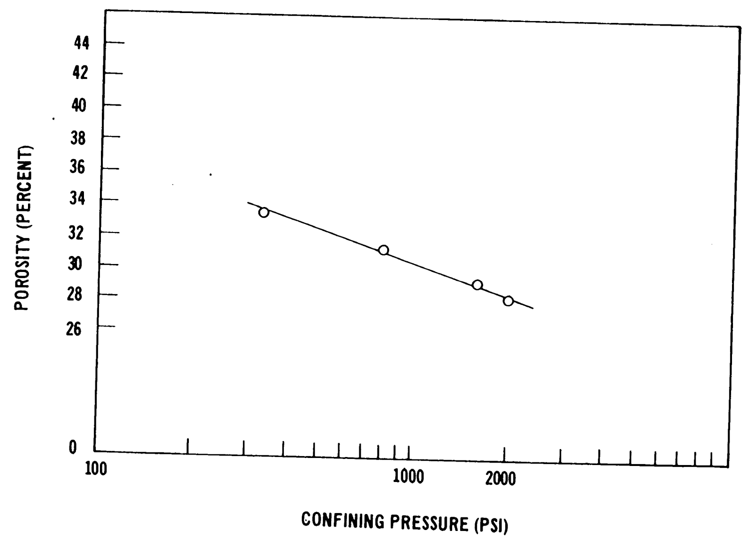


Figure 2-B Effect of Overburden Load on Porosity (T-102) Compacted Dry

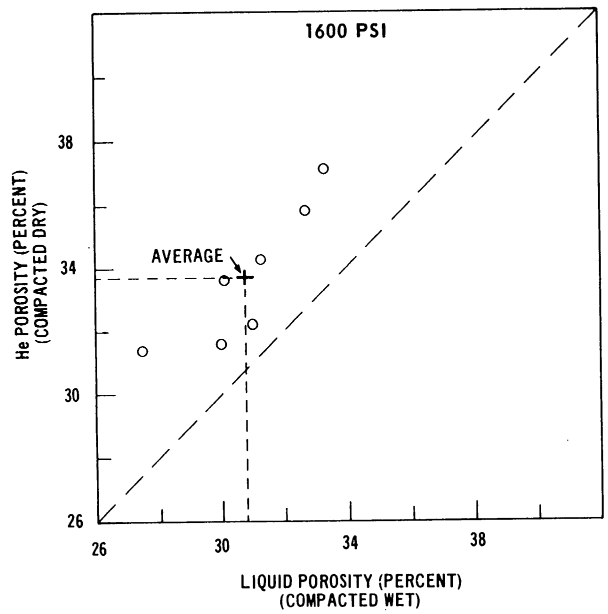


Figure 3-A Effect of Liquid on Sand Compaction (T-104)

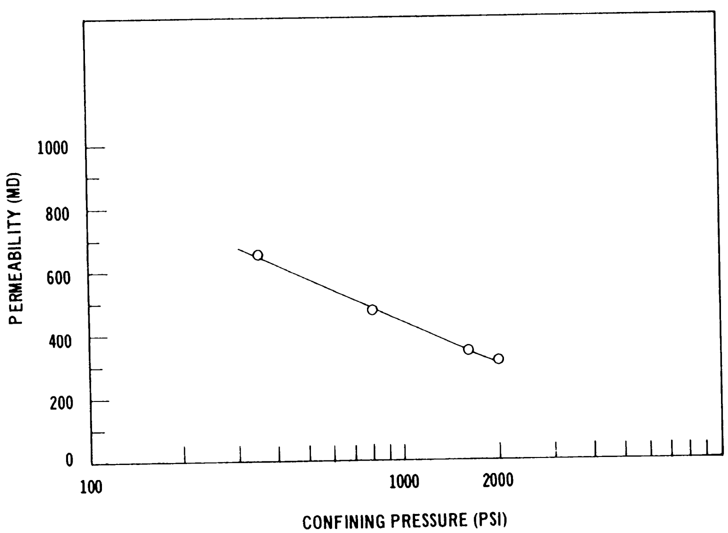


Figure 3-B Effect of Overburden Load on Permeability (T-104) Compacted Dry

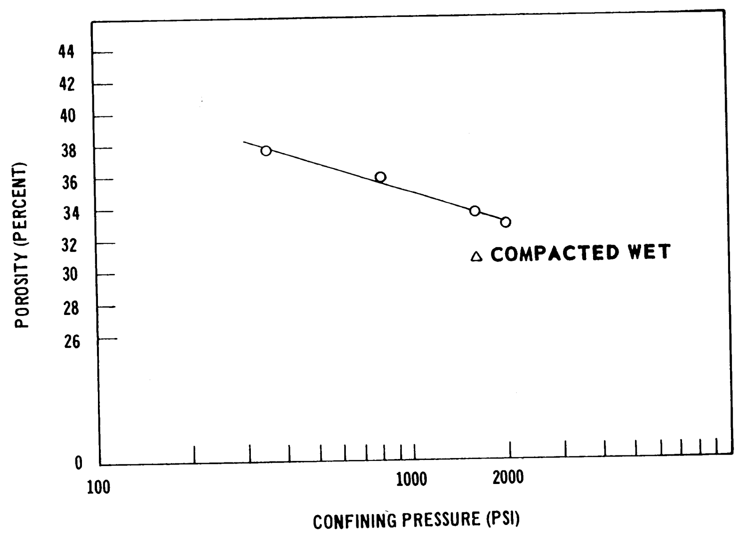


Figure 3-C Effect of Overburden Load on Porosity (T-104) Compacted Dry

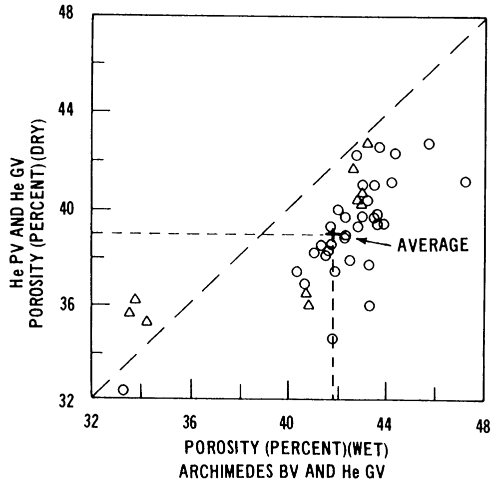


Figure 4-A Effect of Method on Porosity (T-103-Rd)

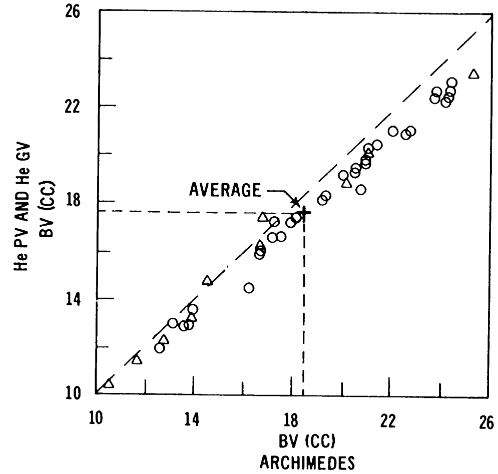


Figure 4-B Effect of Method on Bulk Volume (T-103-Rd)

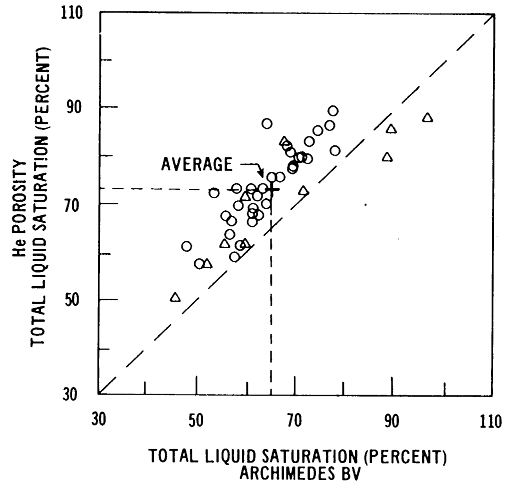


Figure 4-C Effect of Porosity Method on Total Liquid Saturation (T-103-Rd)

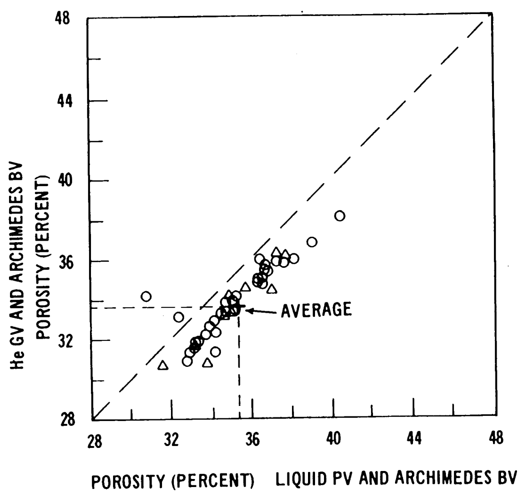


Figure 5-A Effect of Method on Porosity (T-103-Rd, B Samples)

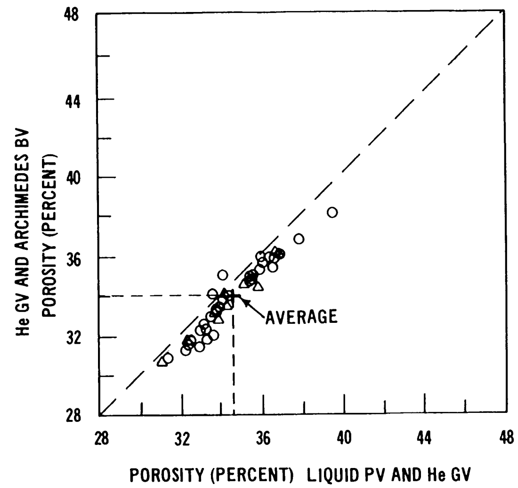


Figure 5-B Effect of Method on Porosity (T-103-Rd, B Samples)

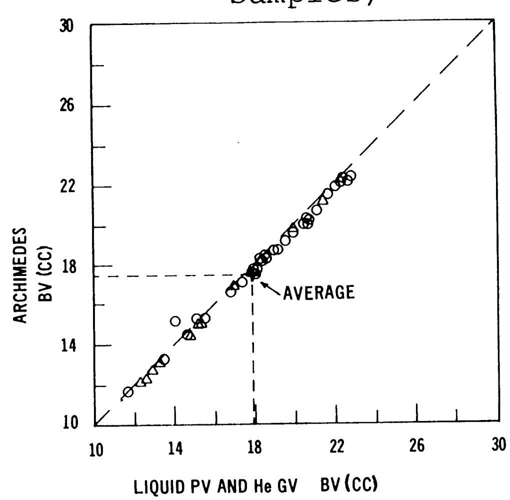


Figure 5-C Comparison of Bulk Volume Methods (T-103-Rd, B Samples)

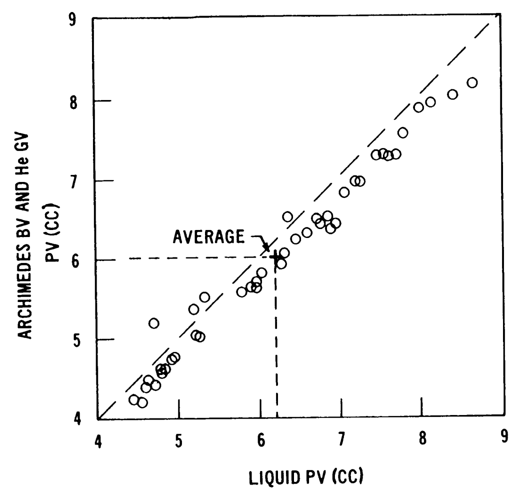


Figure 5-D Comparison of Pore Volume Methods (T-103-Rd, B Samples)

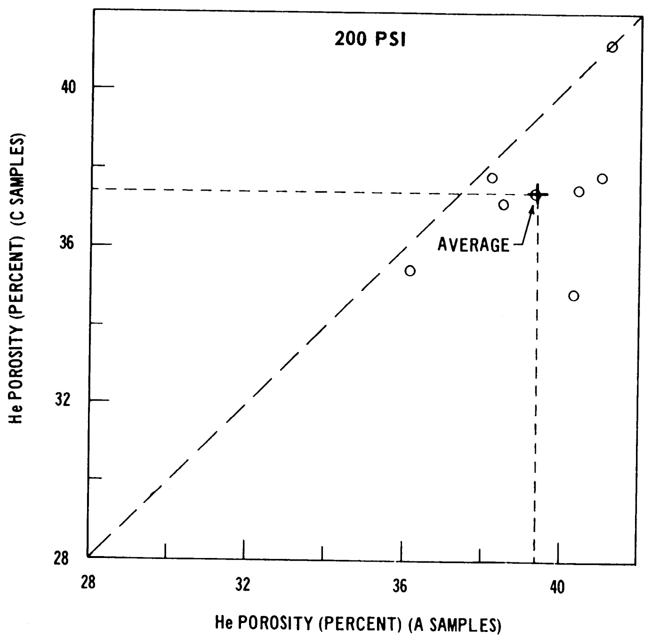


Figure 6-A Comparison of C Samples with Corresponding A Samples (T-103-Rd)

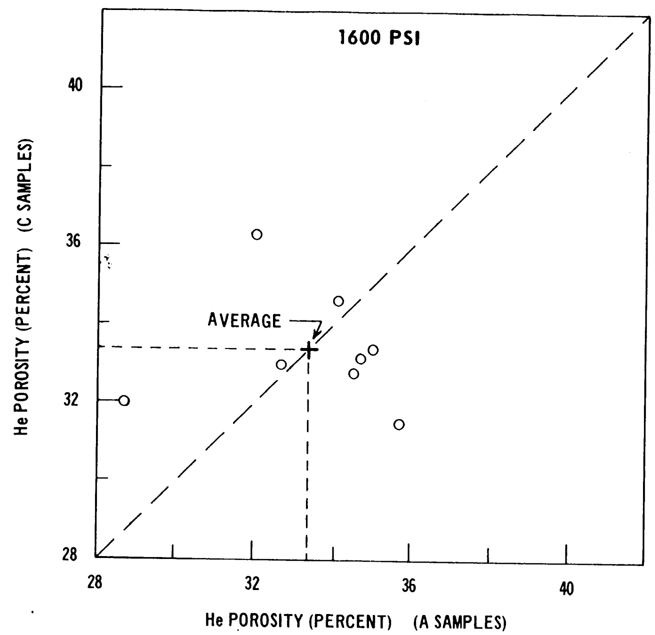


Figure 6-B Comparison of C Samples with Corresponding A Samples (T-103-Rd, Compacted Dry)

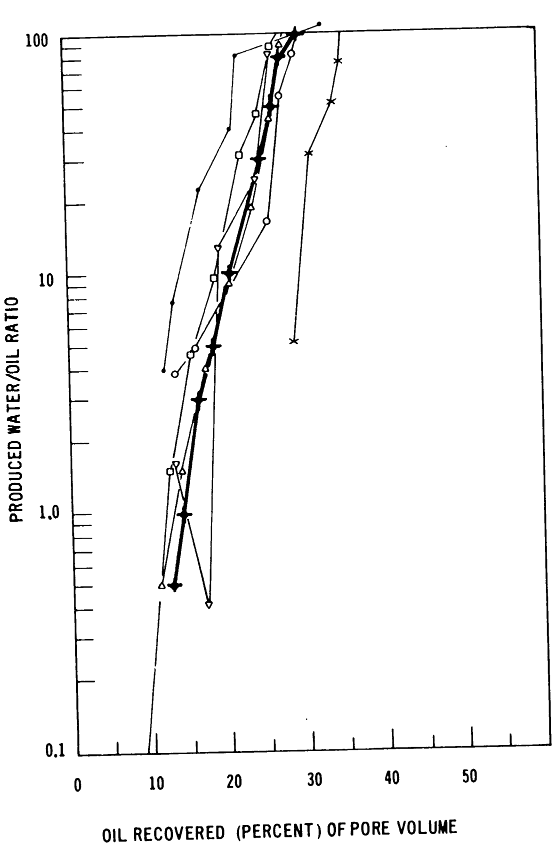


Figure 7-A Results of Waterflood Susceptibility Tests on Six E Samples at 1600-psi Confining Pressure (T-103-Rd)

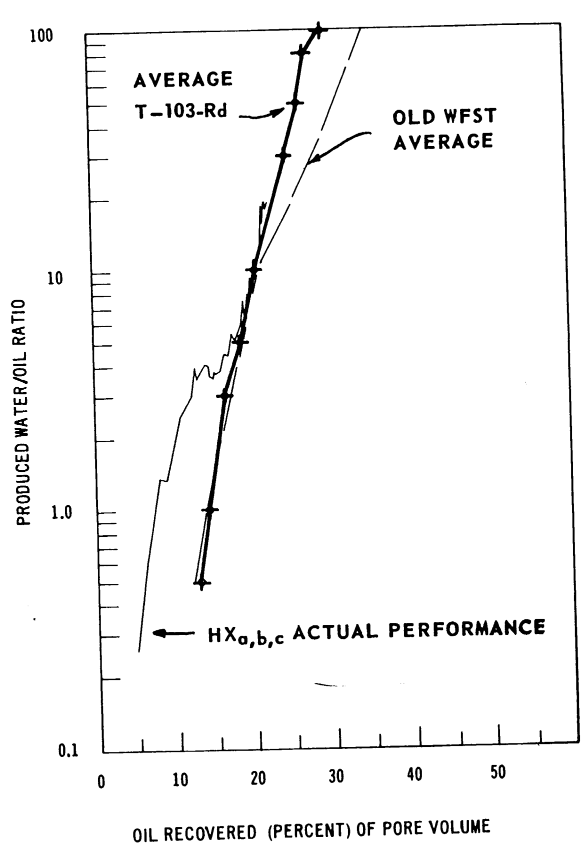


Figure 7-B Comparison of Waterflood Susceptibility Test Data with Actual Recovery from $HX_{a,b,c}$

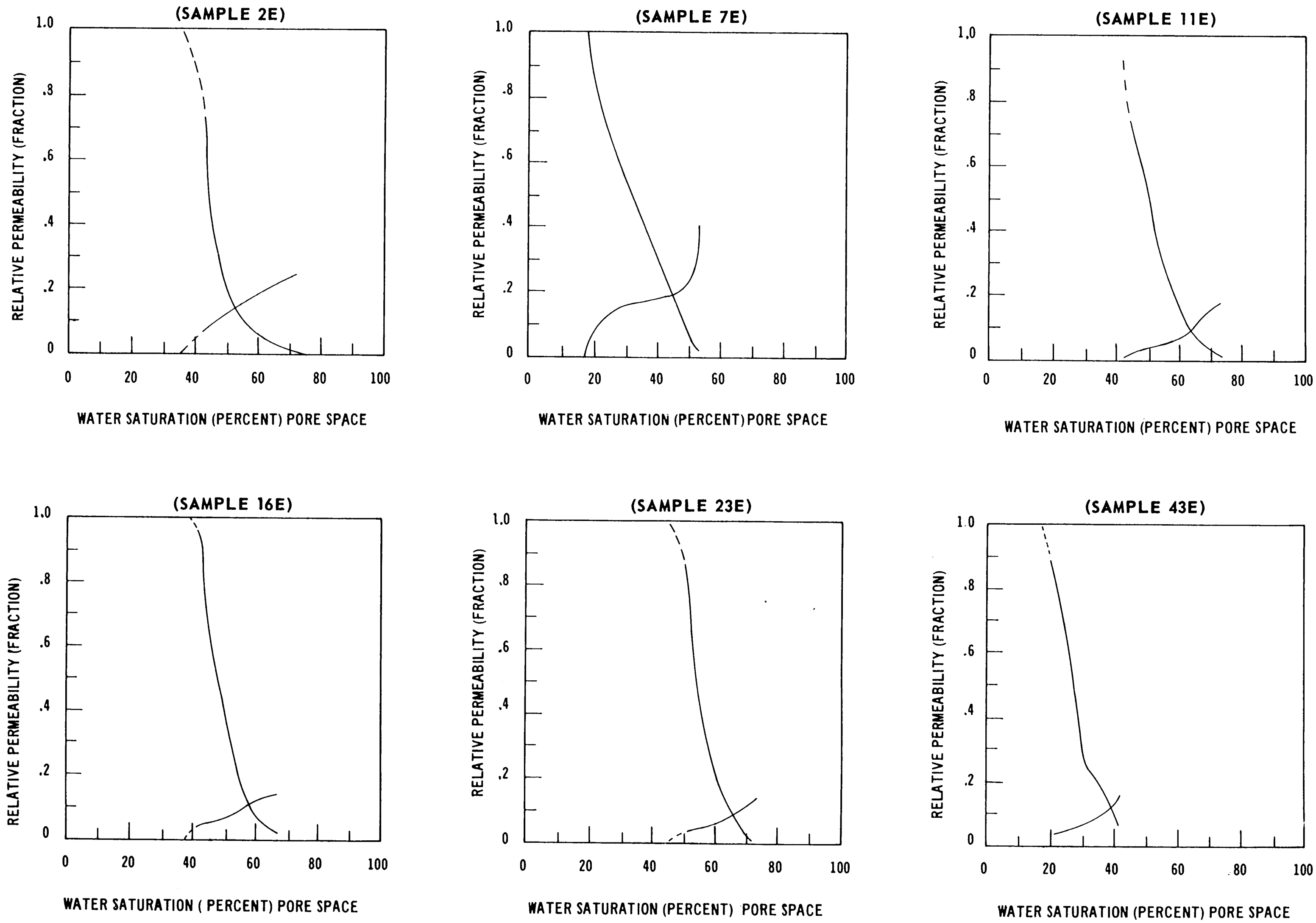


Figure 8 Relative Permeability Curves for Six E Samples at 1600-psi Confining Pressure (T-103-Rd)

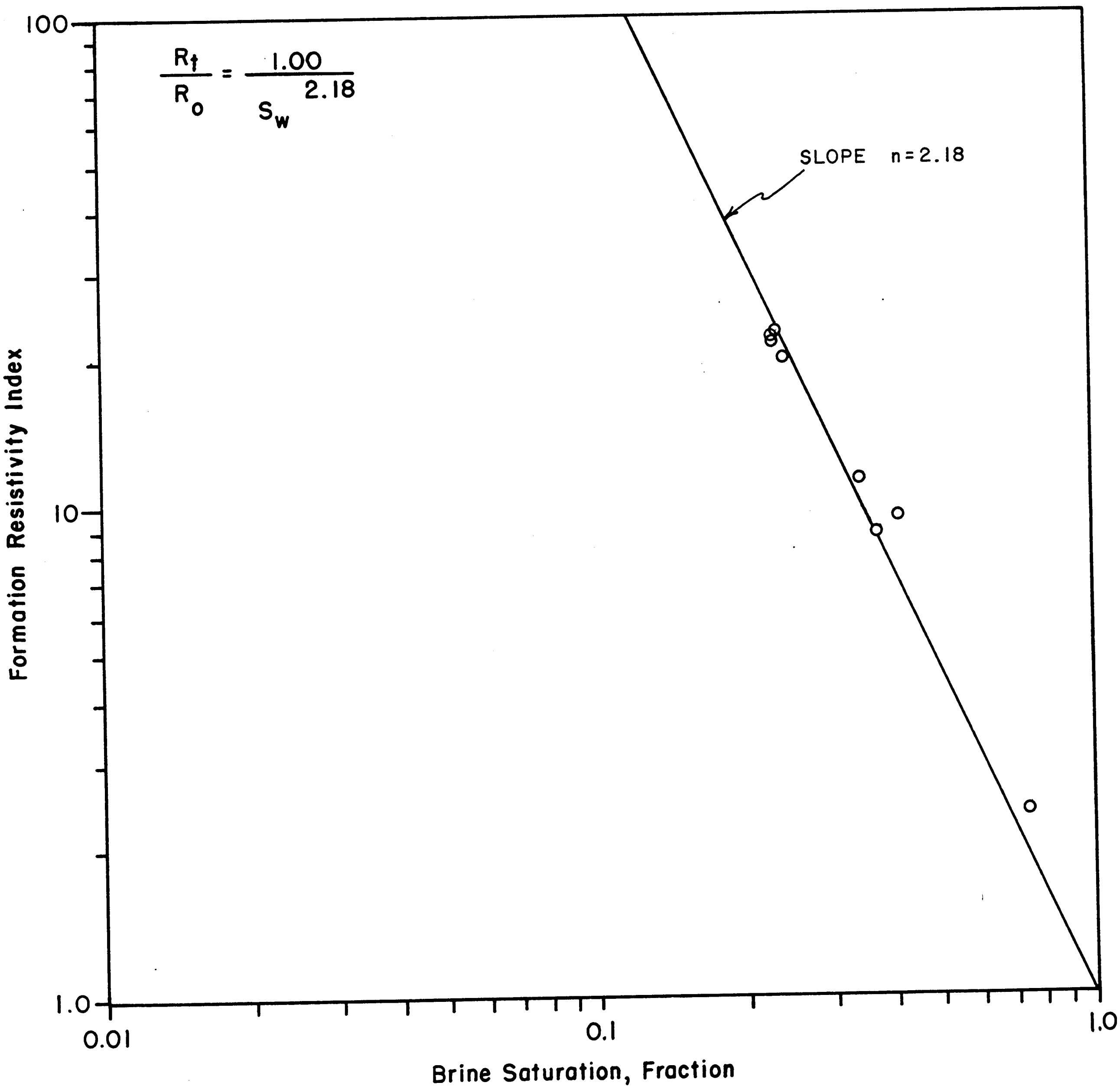


Figure 9 Formation Resistivity Index (T–103–Rd)

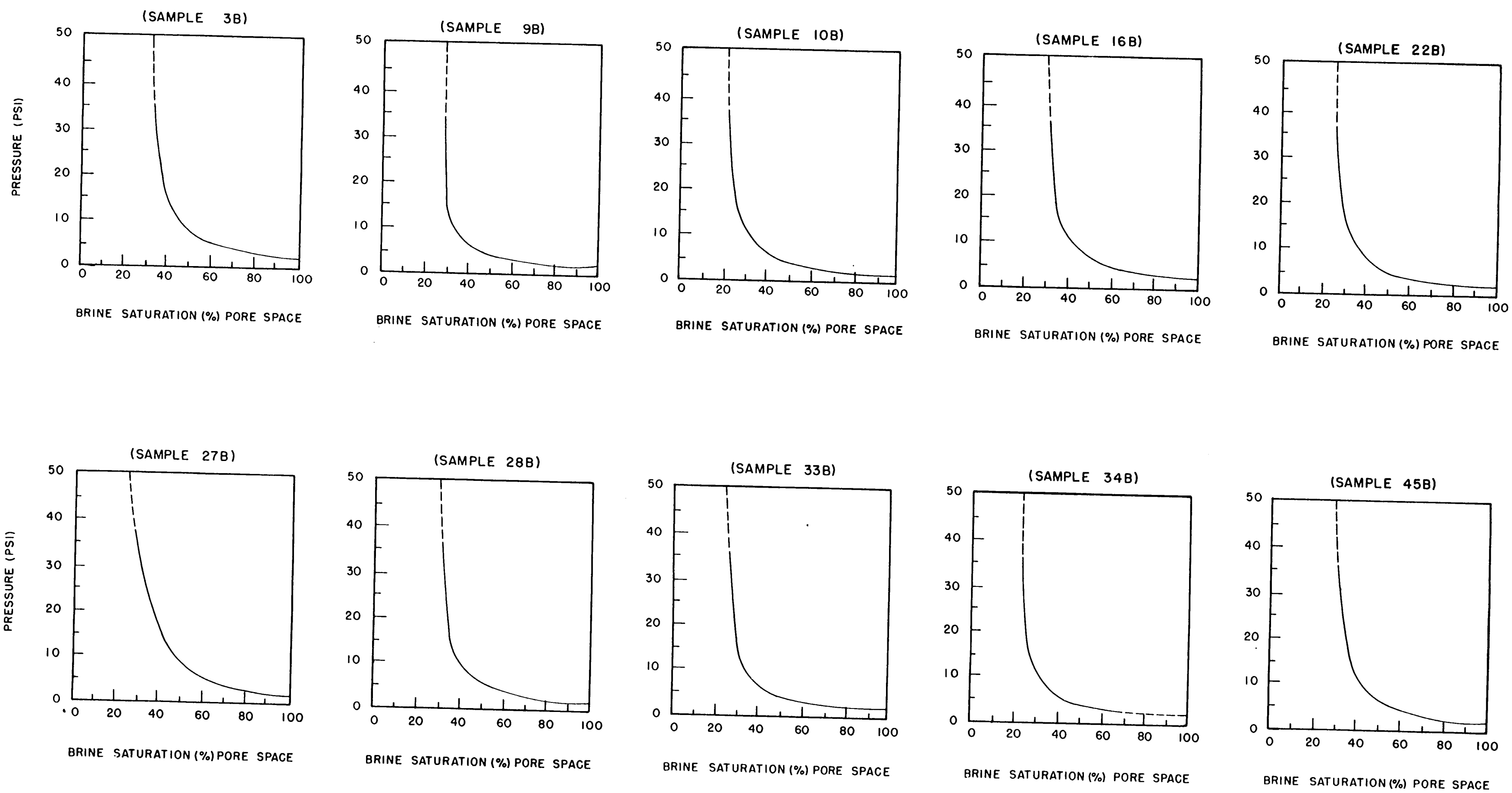


Figure 10 Air — Brine Capillary Pressure for Ten B Samples (T-103-Rd)

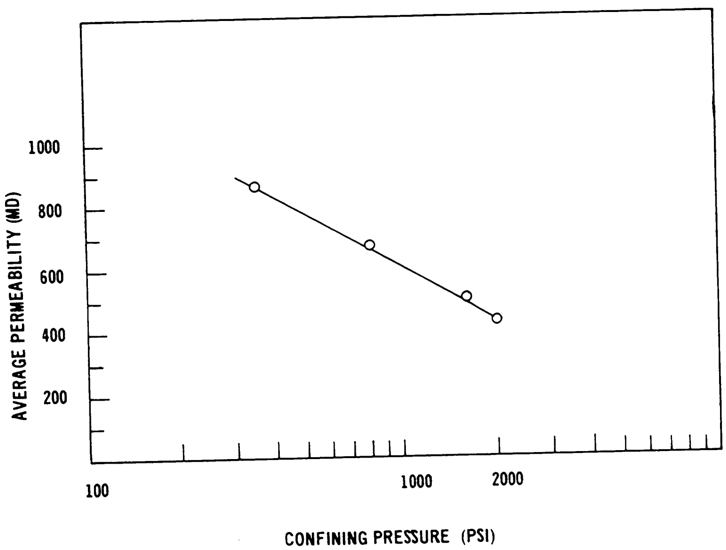


Figure 11-A Effect of Overburden Load on Permeability (T-103-Rd)

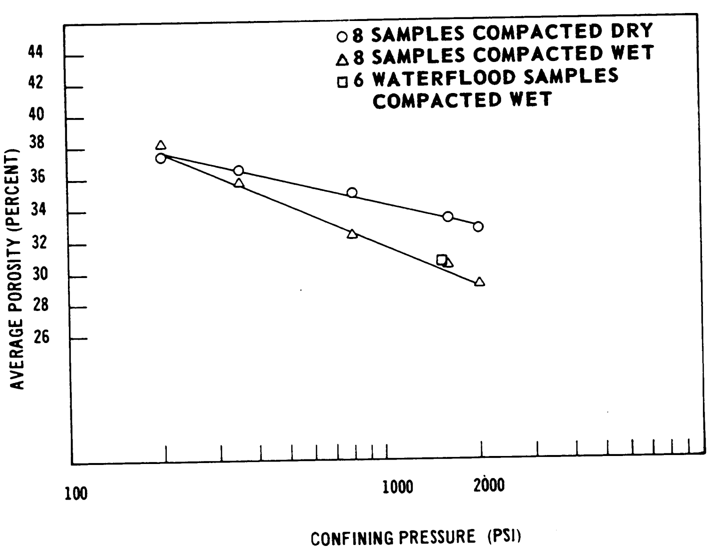


Figure 11-B Effect of Overburden Load on Porosity for Samples Compacted Dry and Samples Compacted Wet (T-103-Rd)

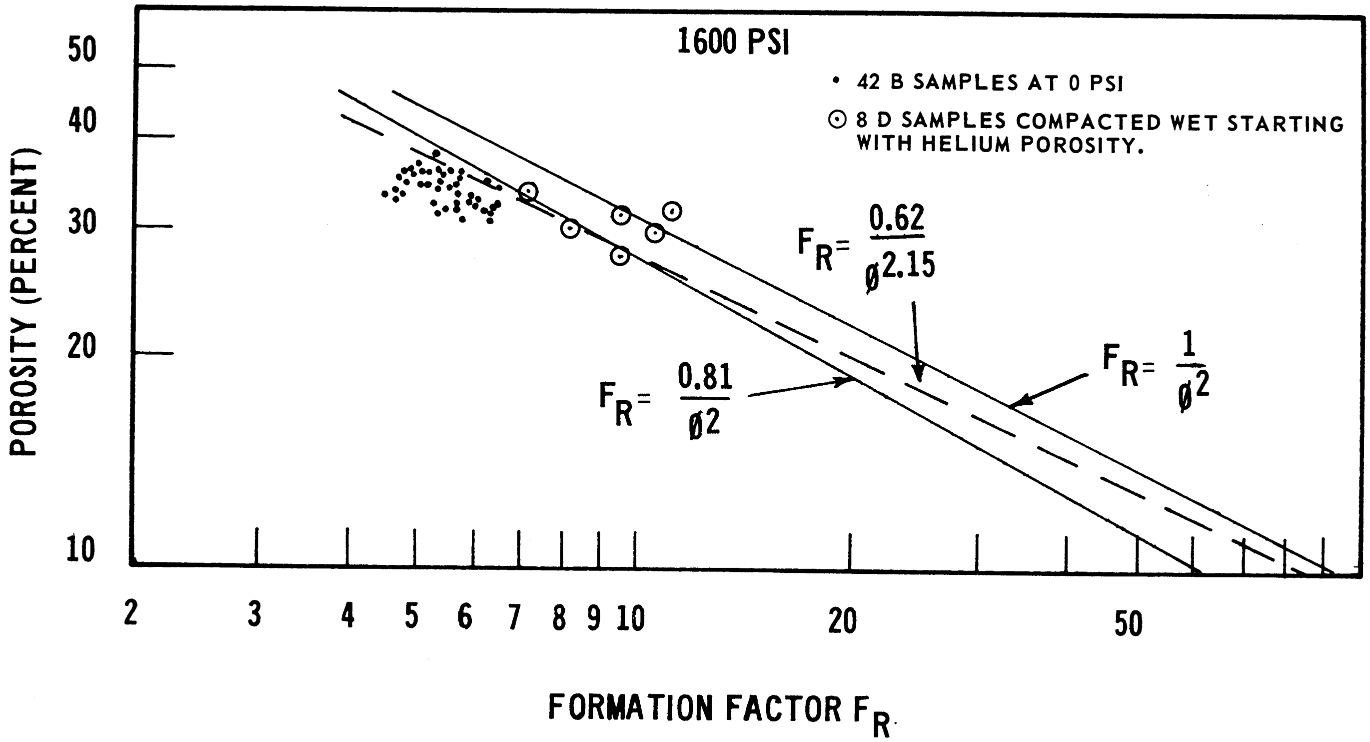


Figure 12 Formation Factor versus Porosity for T-103-Rd

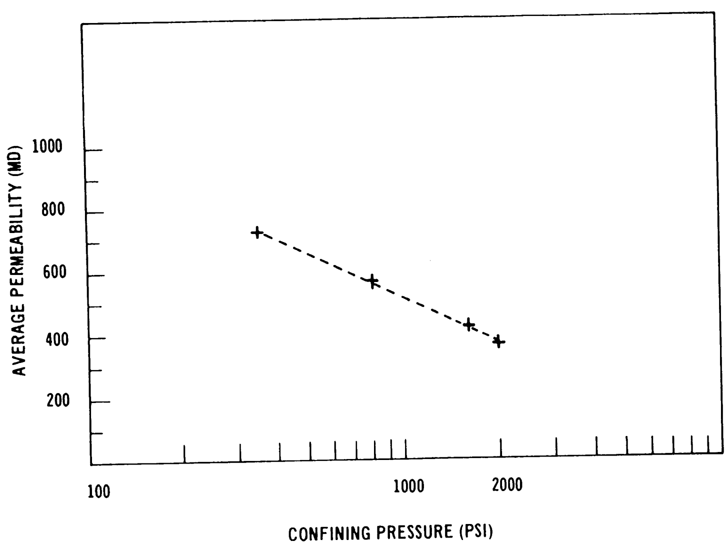


Figure 13-A Effect of Overburden Load on Permeability (Average of All Data for FT-1, T-102, T-103-Rd, and T-104)

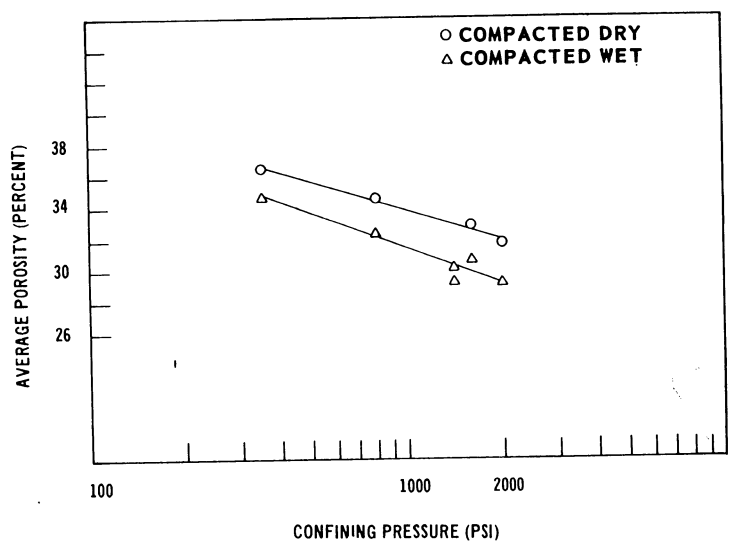
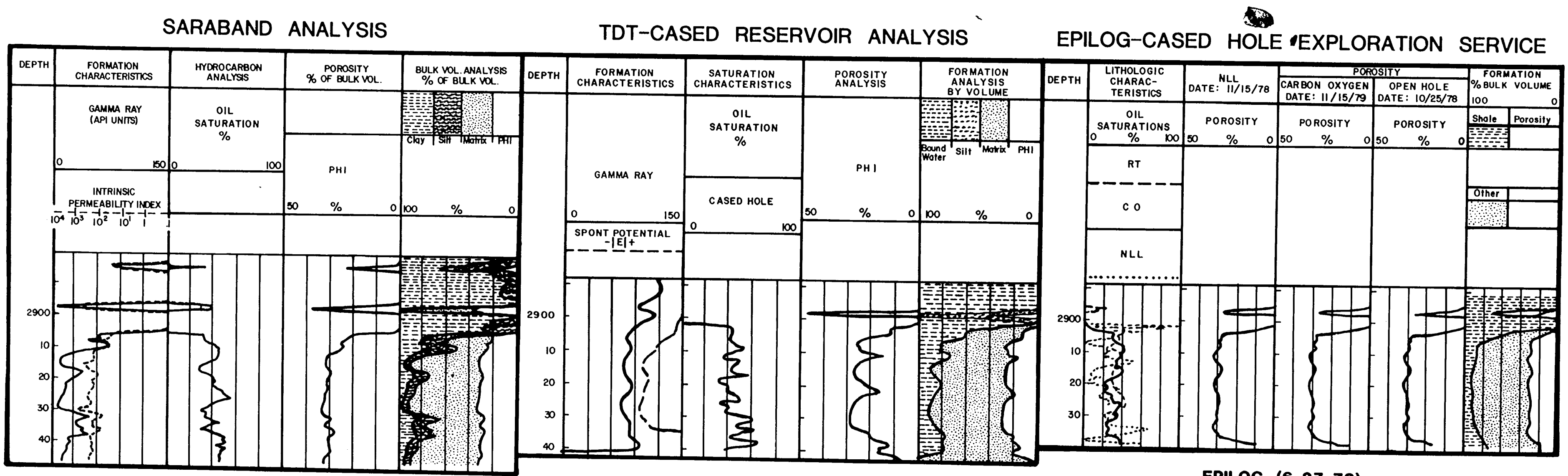


Figure 13-B Effect of Overburden Load on Porosity (Average of All Data Compacted Dry and Compacted Wet for FT-1, T-102, T-103-Rd, and T-104)



SARABAND (8-20-80)

DEPTH	2906-2946	POROSITY, %	29.0
NET FEET	41	So, %	40.8
PERM INDEX	157	BBL/A-FT	918
CLAY VOL., %	10		

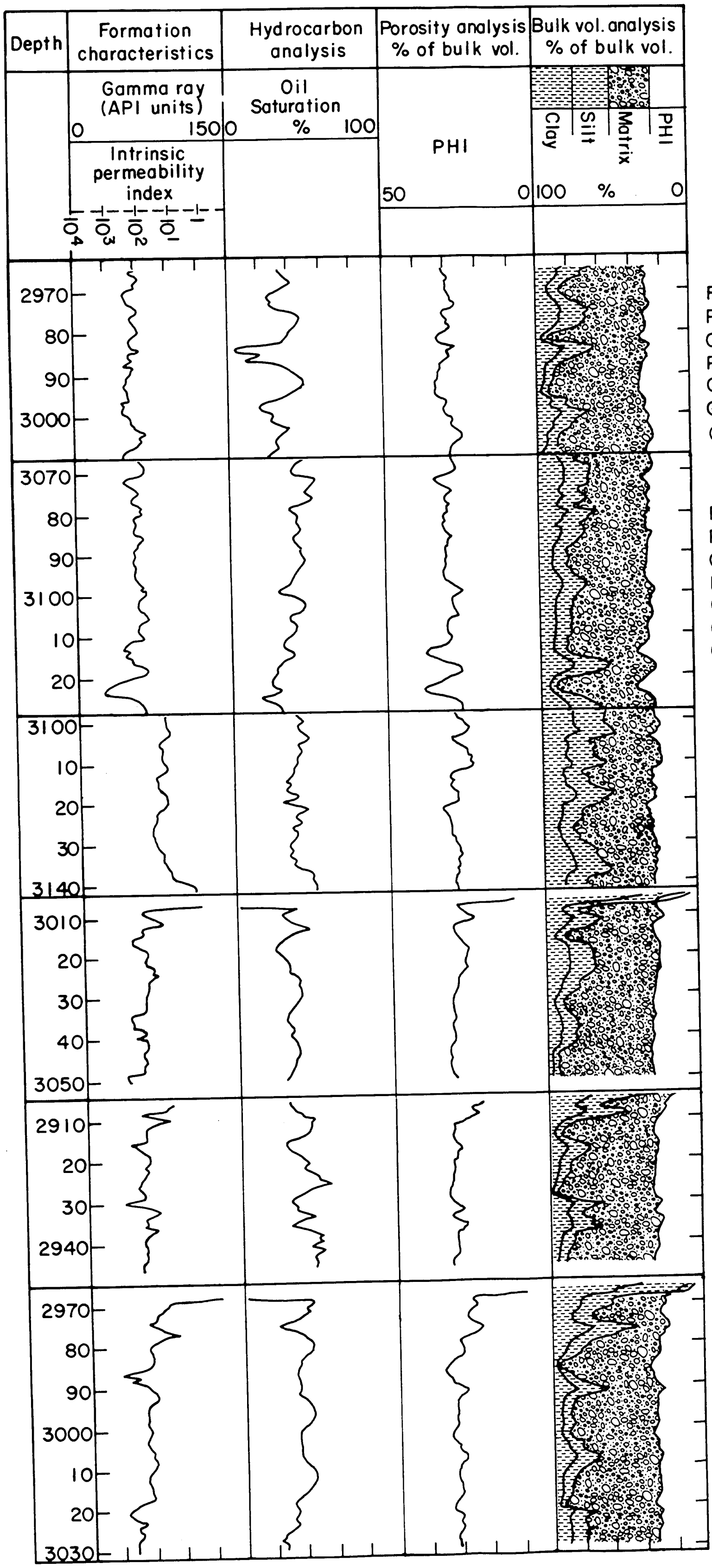
TDT LOG (6-26-79)

DEPTH	2905-40
NET FEET	35
PERM INDEX	104
POROSITY	23.1
So, %	46
BBL/A-FT	824

EPILOG (6-27-79)

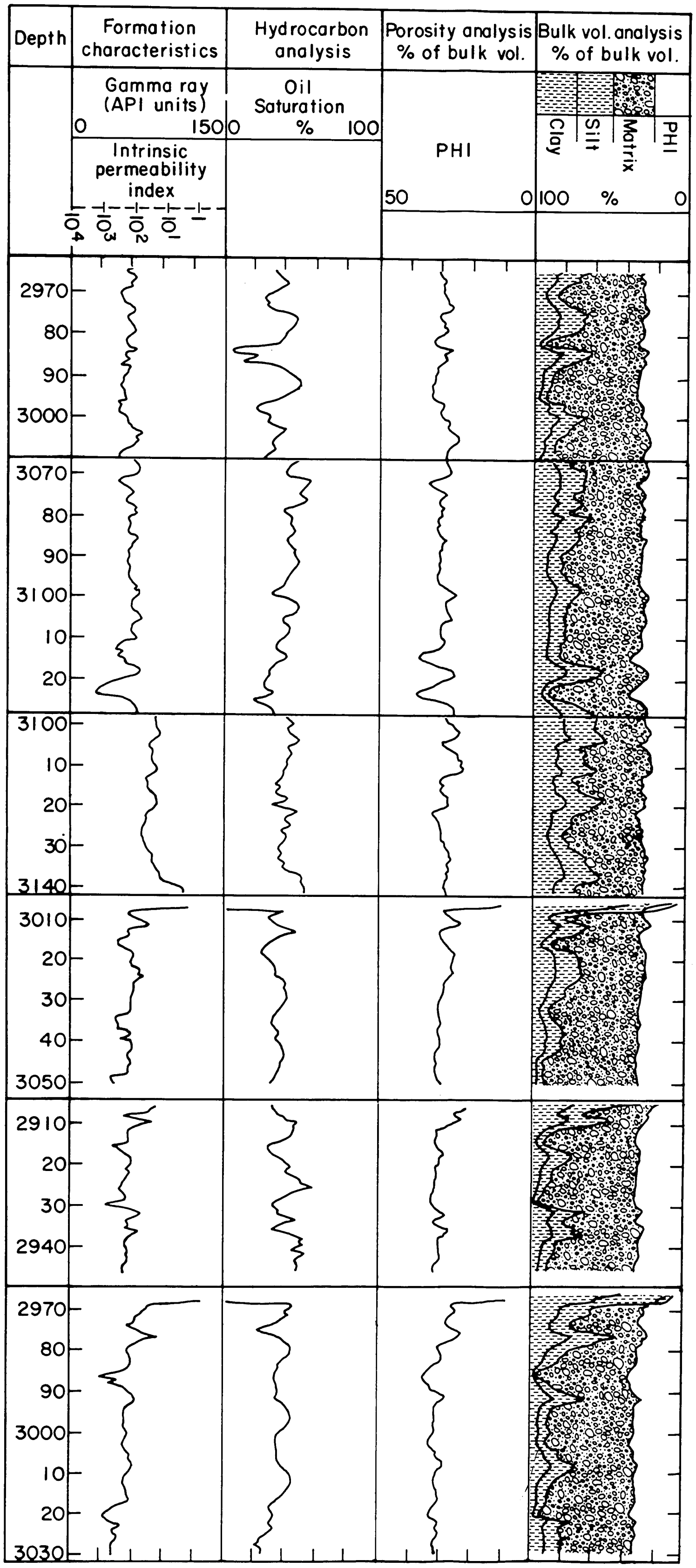
				BBL/A-FT
DEPTH	2904-37	So, NLL, %	26.1	587
NET FEET	34.	So, Rt, %	32.9	740
PERM INDEX	124.	So, C/O, %	32.6	733
POROSITY,%	29.0	SHALE VOL., %	14.	

FIGURE 14 ELECTRICAL LOG ANALYSIS – THREE METHODS HX_a SAND (T-103 Rd)



	Hand picked	Coates final Saraband	Original - Service Co.
FT-1			
FT Sand	46	46	46
Porosity, %	28.8	28.2	27.8
Oil sat., %	34.3	33.6	35
Perm index	82	164	157
Clay, %	8	10.1	15
Grain density	2.67	2.67	2.68
Oil, B/A ft.	766	735	755
FT-3			
FT Sand	67	67	67
Porosity, %	29.7	27	27.5
Oil sat., %	40	39.5	38
Perm index	105	202	122
Clay, %	11	12.9	14
Grain density	2.69	2.69	2.68
Oil, B/A ft.	923	827	810
T-101			
FT Sand	44	44	49
Porosity, %	27.7	26.8	26
Oil sat., %	39	40	37
Perm index	45	82	84
Clay, %	15.	16.6	16
Grain density	2.69	2.69	2.68
Oil, B/A ft.	845	832	750
T-102			
FT Sand	43	43	44
Porosity, %	29.7	28.2	30.3
Oil sat., %	35	34.6	37
Perm index	110	140	154
Clay, %	8	10.3	8.5
Grain density	2.68	2.68	2.68
Oil, B/A ft.	800	757	870
T-103 RD			
FT Sand	41	41	33
Porosity, %	31	29	24.6
Oil sat., %	42	40.8	35
Perm index	62	157	64
Clay, %	6	10.2	25
Grain density	2.72	2.71	2.68
Oil, B/A ft.	1010	918	668
T-104			
FT Sand	62	62	52
Porosity, %	31	29.6	28.1
Oil sat., %	35	36.1	40
Perm index	102	213	125
Clay, %	8	10.2	11
Grain density	2.68	2.68	2.68
Oil, B/A ft.	854	829	872

Figure 15 Saraband Analyses for HX_a Sand



	Hand picked	Coates final Saraband	Original - Service Co.
FT-1			
FT Sand	46	46	46
Porosity, %	28.8	28.2	27.8
Oil sat., %	34.3	33.6	35
Perm index	82	164	157
Clay, %	8	10.1	15
Grain density	2.67	2.67	2.68
Oil, B/A ft.	766	735	755
FT-3			
FT Sand	67	67	67
Porosity, %	29.7	27	27.5
Oil sat., %	40	39.5	38
Perm index	105	202	122
Clay, %	11	12.9	14
Grain density	2.69	2.69	2.68
Oil, B/A ft.	923	827	810
T-101			
FT Sand	44	44	49
Porosity, %	27.7	26.8	26
Oil sat., %	39	40	37
Perm index	45	82	84
Clay, %	15.	16.6	16
Grain density	2.69	2.69	2.68
Oil, B/A ft.	845	832	750
T-102			
FT Sand	43	43	44
Porosity, %	29.7	28.2	30.3
Oil sat., %	35	34.6	37
Perm index	110	140	154
Clay, %	8	10.3	8.5
Grain density	2.68	2.68	2.68
Oil, B/A ft.	800	757	870
T-103 RD			
FT Sand	41	41	33
Porosity, %	31	29	24.6
Oil sat., %	42	40.8	35
Perm index	62	157	64
Clay, %	6	10.2	25
Grain density	2.72	2.71	2.68
Oil, B/A ft.	1010	918	668
T-104			
FT Sand	62	62	52
Porosity, %	31	29.6	28.1
Oil sat., %	35	36.1	40
Perm index	102	213	125
Clay, %	8	10.2	11
Grain density	2.68	2.68	2.68
Oil, B/A ft.	854	829	872

Figure 15 (continued)

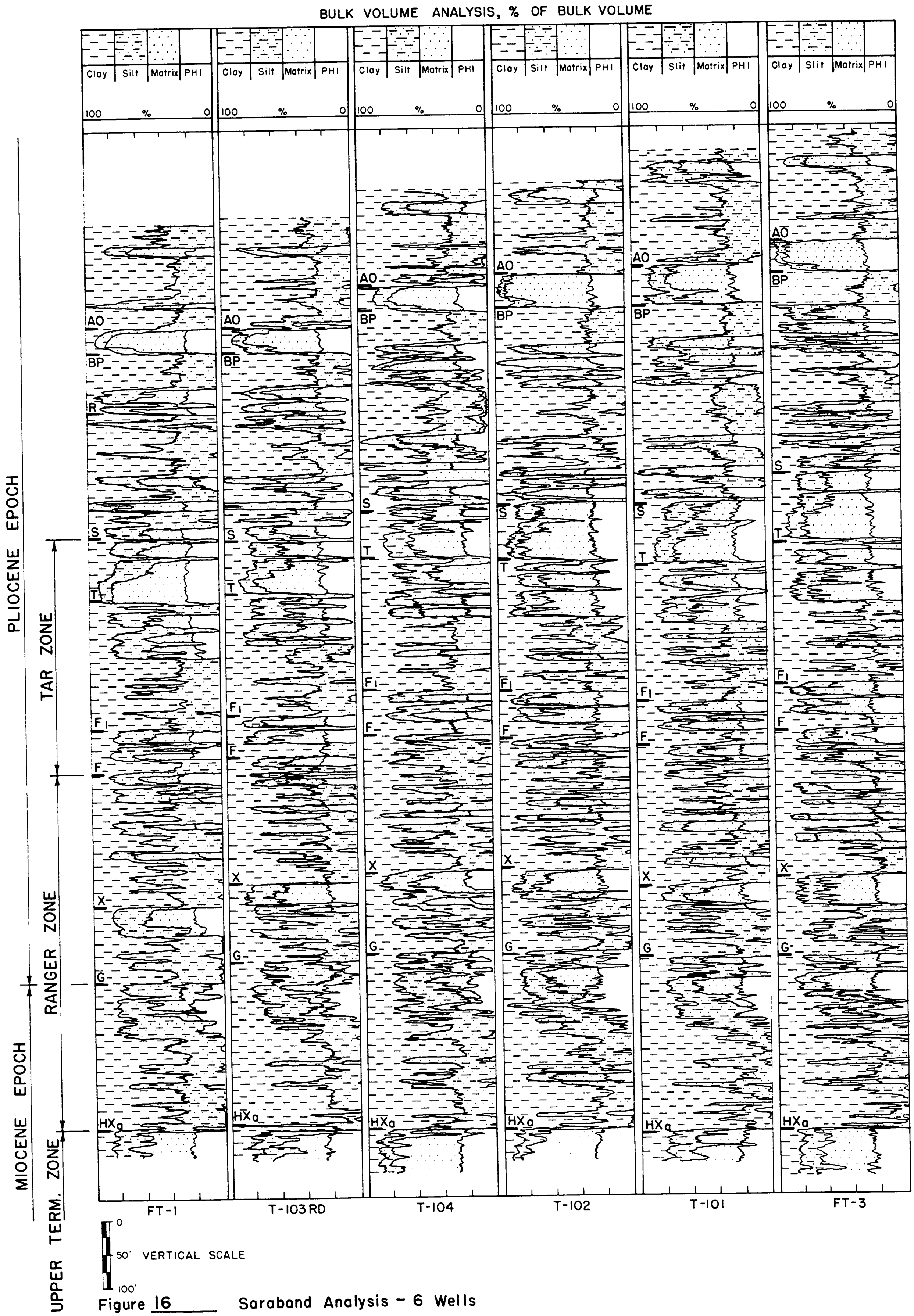


Figure 16 Saraband Analysis – 6 Wells

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