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FINA OIL & CHEMICAL COMPANY

QUARTERLY TECHNICAL PROGRESS REPORT

"APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT AND RESERVOIR CHARACTERIZATION TO OPTIMIZE INFILL DRILLING"

INSTRUMENT NO. DE-FC22-94BC14989 -17

NORTH ROBERTSON UNIT DEPARTMENT OF ENERGY CLASS II OIL PROGRAM PROJECT

REPORTING PERIOD: 6/13/97 TO 9/12/97

This Quarterly Progress Report summarizes the technical progress of the project from 6/13/97 TO 9/12/97.

ACTIVITY II.1 - MANAGEMENT AND ADMINISTRATION

PROJECT MANAGEMENT AND ADMINISTRATION - *TASK II.1.1*

Project Status

The eighteen 10-acre infill wells which were drilled as part of the field demonstration portion of the project are all currently in service with no operational problems. These wells consist of fourteen producing wells and four injection wells. The producing wells are currently producing a total of approximately 500 bopd, down from a peak rate of 900 bopd. Unit production is currently averaging approximately 2,800 bopd, 12,000 bwpd and 17,000 bwipd.

ACTIVITY II.2 - FIELD DEMONSTRATION

IMPLEMENTATION OF FIELD DEMONSTRATION - *TASK II.2.1*

Core Analysis

A total of 2,730 feet of core was taken from four of the Project wells during the Field Demonstration portion of the Project. This core was taken to the Fina core facility in

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Midland, Texas and studied and described by a Fina geologic team, headed up by the Project Geologist, Brian Pregger.

After the initial review and description at the Fina core facility, the cores are being shipped to David K. Davies & Associates in Houston for more detailed descriptive analyses. At this time, approximately 2/3rd's of the core has been analyzed at the Davies lab. In addition, thin-sections are being made and described from the clipped ends of special core plugs which were taken in all potential reservoir intervals and in all rock types. Thin section analysis will allow comparisons of reservoir quality, pore distribution and geometry, and depositional facies within the reservoir. Capillary pressures will also be run on these clipped ends to give us a representative set of data for each individual reservoir rock type. The special core plugs (1.5 inch by 3 inch) were stored in sealed containers filled with degassed lease crude to preserve the native state of the rock characteristics and fluid content.

Special Core Analysis (SCAL)

Approximately 120 preserved (3 inch by 1.5 inch) core plugs were cut from the new whole core in 10-acre infill Wells 1509, 3533, 1510, and 3319 in order to obtain a representative sampling of all 'pay' rock types that were defined during Budget Period I. Thin-section descriptions and capillary pressure measurements are being obtained from the clipped ends of all 120 core plugs.

The SCAL plugs were further screened both visually (thin-sections and slabbed core), and by using a computerized axial tomography (CT) scanning machine at Texas A&M University to eliminate the plugs that possessed major barriers to flow (which is almost always in the form of anhydrite nodules). A CT number of 2550 and above indicates the presence of extensive anhydrite. Pure dolomite has a CT number of about 2350 and the number for pure limestone is around 2250. CT numbers less than 2200 are indicative of good porosity or fracturing.

These studies allowed us to choose 46 plugs, representing the reservoir rock types (Rock Types 1, 2, 3, and 5), for special core studies. The special core analysis program is intended to improve the characterization and description of the reservoir and to provide better reservoir property data for flow simulation.

The special core analysis measurements were performed by Core Petrophysics, Inc. Measured properties include relative permeabilities for oil, water and gas at steady and unsteady-state conditions; centrifuge capillary pressure for oil and water; mercury capillary pressure and pore throat size distribution; formation factor and resistivity index; and rock compressibility. The core samples have been preserved in degassed lease crude oil since they were taken from the well, and relative permeabilities and capillary pressures were measured at reservoir temperature with filtered crude oil and synthetic brine. The relative permeabilities are being measured at net reservoir stress conditions.

The SCAL program was originally intended to measure properties for each of the four significant reservoir rock types, so that the properties could be correlated with the rock types. The plan called for relative permeability and electrical property measurements on 17 plugs and capillary pressure measurements on 17 other plugs, with the plugs distributed with proportions of 5:5:5:2 in rock types 1,2,3 and 5, respectively. This has turned out to be impractical since the permeabilities of the SCAL plugs have been too low to permit measurement of the desired properties in a reasonable amount of time for generally all but the highest quality rock type (Type 1). Therefore only Rock Type 1 will have a complete set of SCAL measurements. This rock type constitutes a small portion of the rock volume but has the greatest effect on reservoir productivity.

This report presents the final results of special core analysis tests using core material from the subject wells.

The forty-six 1.5 inch diameter preserved samples were each flushed with stock tank crude oil at reservoir temperature and the permeability to oil was measured. The results of these oil permeability measurements are presented in Section 1. Note the net confining pressure used in these tests was 500 psi.

The individual results of unsteady-state gas-oil / oil-gas relative permeability tests are presented in Section 2, the Exhibit portion of this report. These results of gas-oil relative permeability tests indicate an average gas saturation of 13.7 % at Kg/Ko = 1.0 samples from Well 1509. The average gas saturation at a Kg/Ko = 1.0 for samples from Well 3533 was 13.2 %. For samples from Well 1510, the average gas saturation was 11.1 % at a Kg/Ko = 1.0. Oil-gas tests results indicate an average final gas saturation of 12.8 % at oil floodout for samples from Well 1509. Samples from Wells 3533 and 1510 exhibited an average final as saturations of 11.6 and 10.1 %, respectively at oil floodout. Note, since there was insufficient two-phase flow data for calculation of oil-gas relative permeability data, only endpoint data are reported.

Section 2 of this report presents the results of steady-state water-oil / oil-water relative permeability tests. These results include tests using native-state samples at reservoir temperature with stock tank oil, and cleaned-state samples at room temperature with laboratory oil. All tests were performed at confining pressure of 2,500 psi.

The results using Sample 1A, Well 1509, under native-state conditions indicate an average oil recovery of 43.5 % pore volume or 57.0 % of the oil-in-place for the water-oil cycle of this test. The oil-water cycle indicate a water recovery of 30.7 percent port volume. Due to apparent plugging this ample was tested in cleaned-state condition. These results indicate a recovery of 62.9 % pore volume during the water-oil cycle, and a recovery of 48.9% pore volume during the oil-water cycle.

The results of steady-state tests using crude oil at reservoir temperature for Sample 21B indicate an oil recovery of 61.7% pore volume or 70.4% of the oil-in-place during the water-oil cycle. The oil-water cycle resulted in a recovery of 36.7% pore volume of water. Samples 18B and 34B were tested in cleaned state condition, using laboratory oil. These data show an average oil recovery of 51.4 % of pore volume.

The steady-state water-gas relative permeability tests were conducted on samples 3A and 25B. These data indicate residual gas saturations that range from 29.7 to 38.9 and average 34.3 % of pore volume.

Section 2 presents the results of reservoir condition unsteady-state water-oil / oil-water relative permeability tests. Samples from Wells 3533, and 1510 were used in these tests. Tests using samples from Well 3533 exhibited an oil recovery of 38.1% pore volume or 50.8% of the oil-in-place during the waterflood. The results tests using samples from Well 1510 indicate an oil recovery of 32.6 % pore volume or 41.6 % of the oil-in-place during the waterflood. Note that several samples plugged during either the waterflood or during the oilflood test. Attempts were made to reverse the effects of core plugging and continue with the tests. This effort was unsuccessful with several samples as noted in the summary of test results.

Section 2 presents the results of the preserved and cleaned state electrical resistivity measurements. These tests include formation factor and resistivity index measurements. The cementation exponents on an individual sample basis varied from 1.96 to 2.63 at NCS over a porosity range of 5.03 to 15.3. The composite m was determined to be 2.17 by regression.

Individual saturation exponents as determined by regression varied from 1.6 to 3.01 with the composite n = 2.06. At the end of the resistivity test the samples were weighed, then dried and weighed again, after correcting for the salts in solution there was reduction in the dry weights of some samples. This indicates some dissolving of minerals in the sample, this is also indicated by the n becoming smaller at the lower saturations. This can be seen on the formation resistivity index Vs Sw plot of the individual samples such as sample 3A, 10B, 24B, 26B, 28B and 34B. This would also explain the low n values of samples 26B, 34B, and 28B.

The results of high-speed water-oil centrifuge capillary pressure tests are presented in Section 6. A composite average final brine saturation at the end of these tests was 28.6 % pore volume. The average final brine saturation of samples from Well 1509 was 25.2 % pore volume. An average final brine saturation for samples from Well 3533 was 27.7 % pore volume, and the average saturation for samples from Well 3319 was 35.6 % pore volume.

Hydrostatic pore volume compressibility results are presented in Section 7 of this report. The results of these tests indicate a range of compressibilities from 1.25 to 10.7 x E-06 vol/vol/psi at 7,500 psi. Samples from Well 1509 exhibited compressibilities from 1.25 to 4.79 x E-06 vol/vol/psi at 7,500 psi. Similar results were found for Sample 2D from Well 1510 which had a compressibility of 4.95 x E-06

at 7,500 psi. However, samples from Well 3319 (Samples 26C and 39C) exhibited higher compressibilities at 7,500 psi (10.7 and 8.00 x E-06 vol/vol/psi).
The results of viscosity measurements and brine compositions for fluids used in this study are provided in Section 8 of this report.

Section 1 of Volume 2 of this report presents the results of high pressure mercury injection capillary pressure tests using trimmed end pieces provided. The results of these tests include capillary pressure, pore throat size histograms, and height above free water calculations.

Test Procedures

Sample and Fluid Preparation

The samples used for these tests were provided by Fina Oil and Chemical Company representatives in a native-state condition. As received, each sample was stored within a sealed glass bottle, submerged under stock tank oil, and cushioned with a layer of sand. Forty six samples were selected for screening tests as requested by Fina. The samples selected for testing were removed from the jars, labeled with the appropriate sample number, and then mounted in individually heated Hassler-type core holders and heated to 110° F. A net confining pressure of 500 psi was applied to each sample. After reaching temperature and pressure equilibrium, the samples were flushed with filtered crude oil while maintaining a temperature of 110° F. A 100 psi backpressure was established to remove any gas which may have been present. After the flushing step was completed, oil permeabilites were measured. The oil permeabilities were used to screen the samples for further use in this special core analysis study. Note that all samples labeled as "A" samples, i.e. 1A, 2A, 3A, etc. are from Well 1509, "B" samples are from Well 3533, "C" samples are from Well 3319, and "D" samples are from Well 1510. A table of oil permeabilies obtained during this screening process are provided in Section 1. Section 1 also provides a list of test samples selected for further tests and the requested net confining stress for each individual sample.

The stock tank oil used for these tests was provided by Fina representatives. Upon receipt, the oil was dewatered using separatory funnels. The water content was checked by placing a weighed amount of crude oil into Dean-Stark type toluene distillation apparatus to measure the water volume. The water content, after the dewatering step, was found to be satisfactory for these tests. After the dewatering step, the oil was loaded into transfer vessels and an attempt was made to filter the oil through 0.45 micron glass filters. The oil plugged the filters at room conditions, so the vessels were placed into an oven at 110° F. Oil was again filtered in a stepwise manner through 1.0 and 0.45 micron glass filters with more success. After the filtering process was completed, the oil viscosity and density were measured at several temperatures. Note that all filtering and transferring of the crude oil during these tests were performed in closed vessels to minimize the loss of light hydrocarbon components in the oil.

The composition of the brine used for these tests was provided by Fina representatives. This brine was used for unsteady-state gas-oil / oil-gas tests, reservoir condition unsteady-state water-oil / oil-water tests, absolute brine permeability measurements, and pore volume compressibility tests. After consultation with Fina representatives, a second brine (a high sulfate brine) was used in centrifuge capillary pressure tests and stady-state water-oil / oil- water tests. The second brine was used to prevent dissolution of anhydrite. The viscosity and density data of these fluids and the composition of test brines are provided in Section 8 of this report.

Gas-Oil / Oil-Gas Relative Permeability Tests

Native-State Tests

The 1 ½-inch-diameter native-state samples used for these tests were placed in core holders and dynamically flushed with stock tank crude oil to remove any gas which may have been present. After flushing, the permeability to oil was measured while maintaining the prescribed net confining pressure. The electrical resistivity of the sample was then measured and recorded. The samples were then gas flooded by injecting humidified nitrogen at a constant pressure, while elapsed time and incremental volumes of produced oil and gas were recorded. Relative permeability was calculated from the production data by using the theory of Weige and Johnson-Bossler-Naumann, which relates relative permeability with core end saturation. Following the gasflood tests, oil-gas relative permeability tests were performed. The samples were injected with oil under constant rate conditions. During the oilflood, measurements of incremental volumes of oil and gas were attempted. After the production of gas ceased, the permeability to oil at oil floodout, was measured. After these tests, the electrical resistivity of each sample was remeasured and recorded.

Cleaned-State Tests

Samples selected for cleaned-state tests were previously used in other tests described in this study. Upon selection for testing, the samples were vacuum and pressure saturated with test brine. The samples were then mounted in Hassler-type core holder, subjected to the prescribed net confining pressure, and flushed with a 27 cp mineral oil to a near-irreducible water saturation (Swi). After reaching Swi, the oil permeabilities were measured. The samples were then gas flooded by injection of humidified gas at a constant pressure, while elapsed time and incremental volumes of produced oil and gas were recorded. Relative permeability was calculated from the production data by using the theory of Weige and Johnson-Bossler-Naumann, which relates relative permeability with core end saturation.

Steady-State Water-Oil/Oil-Water Relative Permeability Tests

Native-State Tests

The samples selected for these tests were placed in a core holder designed for steady-state flow measurements. The cell is equipped with outer flow sections of permeable sandstone and the core samples were placed between the outer sections using Kleenex to provide capillary continuity across the rock assembly. Special pressure taps provided a way to measure flowing pressure differentials across the test core. The core holder and sample were heated to 110° F for these tests.

After measurements of an effective oil permeability, using stock tank oil containing iododecane, the relative permeability test was begun using an oil/water injection ratio of approximately 20:1. Note that the test brine for this project was a high sulfate brine consisting of calcium sulfate, sodium sulfate, magnesium sulfate and strontium sulfate. The oil used for these tests was the stock tank oil provided by Fina Oil and Chemical Company personnel.

Stepwise changes in subsequent injection ratios and finally only water injection produced an increasing water floodout step, the procedural steps were reversed and the samples were tested for steady-state relative permeability with oil saturation increasing.

Throughout each test, the oil and water saturations were determined using an X-ray absorption technique. Following the flow test, calibration scans were made. First, after cleaning, the test core was fully saturated with oil in preparation for a required X-ray scan at So = 100 percent. Following cleaning with pentane and air drying, a second calibration scan was obtained at Sw = 100 percent. Note that the test samples were not removed from the steady-state core holder during any of the above steps and that sample cleaning was accomplished by solvent injection. The determinations of water and oil saturations were then made using the following equation.

$$S_W = 1 - S_o = \frac{\log T_X - \log T_o}{\log T_W - \log T_o}$$

where:

T_w = radiation transmission at S_w = 1.0
T_o = Radiation transmission at S_o = 1.0
T_x = radiation transmission at any water-oil saturation

The difference between Tw and To was greatly increased by adding an X-ray absorber, iododecane , to the oil. The concentration was 10 volume percent. During scan, the X-ray head (i.e., X-ray tube and scintillation counter) traverses the stationary core at a rate of 2.8 cm. per minute.

Saturations at any location along the core can be determined. However, these values usually are averaged and reported as a single saturation value because the test samples are relatively short.

Cleaned-State Tests

Cleaned state tests were performed following the native state tests. The cleaned and dried samples were fully saturated with the sulfate test brine and then flushed to Swi with 27 cp mineral oil. Each sample was then flushed with 1.4 cp laboratory oil containing iododecane. The procedures used in these tests are the same as described for native state-tests.

Steady-State Water-Gas Relative permeability Test Procedures

The samples used for these tests were fully saturated with 100,000 ppm sodium iodide brine. Next, each sample was flushed to a near-irreducible water saturation (Swi) using a 25 cp mineral oil. Nest the samples were flushed with 1.5 cp mineral oil to remove the 25 cp oil. Pentane was injected into each core sample to remove the mineral oil. Humidified nitrogen was flushed through the core to remove the pentane, thus leaving the core sample at a near-irreducible water saturation plus gas saturation. The water-gas steady-state relative permeability tests were performed using a pore pressure of approximately 200 psi to minimize gas expansion effects during the tests. After measurement of a gas permeability at Swi, the relative permeability test was started using an water-gas injection ratio of approximately 1:4,000. Stepwise changes in subsequent injection ratios produced an increasing water saturation condition that ends at trapped gas saturation. All data were collected at conditions of flow equilibrium. Gas and water saturations were measured using a X-ray absorption technique. This technique is described below:

Water-Gas Saturation Calculations

X-ray scans for calibration purposes were made when the core contained only gas and then water. These calibration scans provided a way to measure all partial water-gas saturations. The determination of core gas and water saturations was made using the following equation:

$$S_g = (1 - S_w) = \frac{\log T_x - \log T_w}{\log T_g - \log T_w}$$

where:

Tg = radiation transmission at Sg - 1.0

Tw = radiation transmission at Sw - 1.0
Tx = radiation transmission at any partial gas-water saturation.

The difference between Tg and Tw is greatly increased by addition sodium iodide, an X-ray absorber, to water. During a scan, the X-ray head (i.e., X-ray tube and scintillation counter) traverses the stationary core at a rate of 2.8 cm. per minute. Saturations at any location along the core can be determined. However, because the cores are short, these values usually are averaged and reported in a single saturation value.

Reservoir Conditions Unsteady-State Water-Oil / Oil-Water Relative Permeability Test

The 1 ½-inch-diameter samples used for these tests were previously used in unsteady-state gas-oil relative permeability tests. Upon receipt, the samples were mounted in Hassler-type core holders and electrical resistance measurements were obtained at the prescribed overburden pressure. The samples were then place in a oven at 110° F and allowed to reach temperature equilibrium. The net confining pressure was also raised to the amount prescribed for each sample. After reaching test temperature, the samples were flushed with stock tank oil and the oil permeabilities were measured. The samples were then waterflooded with test brine using constant pressure techniques. During the waterflood tests, incremental oil production, time, and pressure drop were periodically measured and recorded. After water floodout, brine permeabilities were measured in the forward and reverse flow directions to detect the presence of mobile fines. The procedure was then repeated using oil as the displacing phase instead of water. Increment volumes of water and oil were collected during the oilflood test. After reaching oil floodout, a permeability to oil was measured. After the oilflood, the samples were removed from the oven and electrical resistance measurements were obtained after reaching temperature equilibrium at room conditions. The samples were then removed from the core holders and placed in Dean-Stark type toluene distillation apparatus to determine core liquid saturations. The samples were then cleaned in toluene for 24 hours before drying in an oven at 230° Fahrenheit for 48 hours. After drying, air permeabilities and helium porosities were measured at the prescribed net confining pressure. Unsteady-state water-oil / oil-water relative permeability test results were calculated from production data using the theories of Weige and Johnson-Bossler-Naumann, which relate relative permeabilities to core end saturations.

Room Conditions Unsteady-State Water-Oil Relative Permeability Tests

The 1 ½-inch-diameter cleaned-state core samples used for these tests were selected by Fina Representative. Sample Nos. 7B, 24B, and 26B were mounted in Hassler-type core holders and flushed with a 27 cp. Laboratory mineral oil. After flushing the samples, oil permeabilities were measured at the prescribed net confining pressure. The samples were then waterflooded with test brine using constant rate techniques.

During the waterflood tests, incremental oil production, time, and pressure drop were periodically measured and recorded. After water floodout, brine permeabilities were measured in the forward and reverse flow directions to detect the presence of mobile fines. The samples were then removed from the core holders and placed in Dean-Stark type toluene distillation apparatus to determine core liquid saturations. The samples were then cleaned in toluene for 48 hours before drying in an oven at 230° Fahrenheit for 24 hours. After drying, air permeabilities and helium porosities were measured at 2,000 psi net confining pressure. Unsteady-state water-oil relative permeability test results were calculated from production data using the theories of Weige and Johnson-Bossler-Naumann, which relate relative permeabilities to core end saturations.

Electrical Resistivity Measurements

Sample Preparation

Fifteen 1 ½-inch-diameter samples were used for the resistivity study. The samples were extracted with toluene followed by methanol in a sidearm-style soxhiet extractor to remove hydrocarbons as well as precipitated salt. The samples were then dried to a constant weight at 240 degrees F in a convection oven. Permeability to air and Boyle's Law porosity values (using helium as the gaseous phase) were measured for each sample. The samples were evacuated, then pressure saturated @ 1500 psig with a simulated formation brine prepared from formation brine analysis as provided by representatives of Fina Oil and Chemical Company. Saturations were verified gravimetrically upon removal from the saturating cell.

Formation Factor at net confining stress

Brine saturated porous plates (15 bar) were placed on the downstream ends of each sample. They were then placed in core holders and were flushed with the simulated formation brine at minimum confining stress. Flow was terminated and the net confining pressure (NCS) was elevated to the requested confining stress. Brine volume expelled was recorded and used to calculate porosity at NCS. Flow was resumed and the sample resistance was monitored until stable to ensure that ionic equilibrium was achieved. Resistance and phase angle measurements were made using an alternating current at a frequency of 1000Hz. Sample resistance data were obtained by deducting the porous plate resistance and by making a correction for the phase angle.

Formation resistivity factors were calculated from these test results. Cementation exponents (m) were calculated on an individual sample basis assuming a = 1.0 (where a is the Y axis intercept of a plot of formation Factor Vs porosity). The average m for all samples was determined by regression assuming a = 1.0.

Resistivity Index at net confining stress

At the conclusion of the formation factor testing, each sample was injected with humidified nitrogen gas at selected pressures to displace the brine through a porous plate on the downstream side of the sample. The brine volume produced at each pressure was measured volumetrically and was recorded to determine sample saturation. At each pressure, resistance and phase angle measurements were also made. Sample resistance data were correcte for phase angle and porous plates. The resistivity indices, corresponding water saturations and the saturation exponents (n) were calculated from these test results. At the conclusion of the tests the samples were removed from the core holders and weighed to verify the final saturations gravimetrically. These data are reported in tabular and graphical form in the resistivity section.

High-Speed Centrifuge Capillary Pressure Tests

Samples selected for water-oil / oil-water centrifuge capillary pressure tests were trimmed to the appropriate length for centrifuge tests and placed into the centrifuge apparatus under test brine. The brine used in these tests was a high sulfate brine described in Section 8. The oil saturation was decreased by stepwise increase of the rotational speed of the centrifuge. The volume of oil displaced at each speed was volumetrically measured after attaining saturation equilibrium. Following this, the samples were tested for oil increasing centrifuge capillary corresponding core end saturations were calculated. The core end saturations were calculated using the theory of Hassler and Brunner.

Hydrostatic Pore Volume Compressibility Test

The 1 ½-inch-diameter core samples used these tests were cleaned in hot toluene and alcohol and placed in an oven and dried at 240° F overnight. After drying, the air permeability and helium porosity of each sample was measured at standard conditions of 400 psi confining pressure. The samples were then vacuum and pressure saturated with test brine. After saturation, the samples were mounted in Hassler-type core holders and flushed with test brine while maintaining a backpressure to insure 100 percent brine saturation. The samples were placed in an oven at 90° F to insure constant temperature conditions. After allowing the samples to stabilize at a 500 psi net overburden pressure, the net confining pressure was increased in a stepwise manner to 1,000, 3,500, 4,500, 5,500, 6,500, and 7,500 psi. The fluid expelled from the core was measured after each pressure increase, and these data were used to calculate the percentage of pore volume reduction at each met overburden pressure. Hydrostatic pore volume compressibility was calculated from the pore volume reduction data. During these series of measurements, the pore pressure was zero.

High Pressure Mercury Injection Capillary Pressure Tests

Trimmed endpieces from the samples used in other special core analysis tests were received from Fina representatives. These samples were trimmed to the appropriate size for mercury injection tests and then cleaned in hot toluene and alcohol. After cleaning, the samples were dried in an oven at 240° F. The samples were placed in a desiccator to cool after the drying step. Helium porosity measurements were obtained using a modified Boyles Law helium porosimeter before mounting the samples in the mercury injection apparatus. Mercury was then injected into the sample using pressures that ranged from 1 to 60,000 psia. From the resulting data, capillary pressure relationships and pore throat-size distributions were computed.

LIST OF TEST SAMPLES

Fina Oil and Chemical Company
North Robertson Unit
Wells 1509, 1510, 3319, and 3533
North Robertson Unit
Gaines County, Texas

Well	Sample Number	Depth, feet	Prescribed Net Confining Pressure	Screening Oil Permeability @ 500 psi net confining pressure, md.
1509	1A	6347.8	5,450	4.71
	2A	6348.8	5,300	0.0800
	3A	6349.9	4,850	0.761
	4A	6350.2	5,050	0.105
	5A	6352.9	5,200	0.0905
	14A	7068.4	6,125	0.363
	19A	7086.3	5,950	<0.001
	27A	7139.9	6,250	<0.001
	28A	7188.6	6,200	0.0485

	29A	7200.0	5,925	<0.001
	34A	7210.1	5,700	0.0404
	35A	7220.1	5,650	0.0250
	36A	7226.0	6,000	NOT TESTED
	37A	7227.2	6,050	NOT TESTED
3533	6B	6400.9	5,200	0.672
	7B	6,401.9	5,000	2.66
	8B	6402.2	4,925	0.531
	10B	6404.1	4,925	0.583
	18B	6422.9	4,825	4.53
	20B	6427.1	4,875	102
	21B	6427.9	4,950	14.1
	22B	6428.1	4,925	8,72
	24B	6951.7	5,675	11.4
	25B	6952.1	5,600	19.7
	26B	6952.9	5,625	5.82
	27B	6954.6	5,550	<0.001
	28B	7135.9	5,750	0.274
	30B	7180.6	6,225	<0.001
	31B	7181.4	6,400	<0.001

LIST OF TESTS SAMPLES

Fina Oil and Chemical Company
North Robertson Unit
Wells 1509, 1510, 3319, and 3533
North Robertson Unit
Gaines County, Texas

Well	Sample Number	Depth, feet	Prescribed Net Confining Pressure	Screening Oil Permeability @ 500 psi net confining pressure, md.
3533	33B	7187.3	5,560	<0.001
	34B	7191.2	5,700	11.6
3319	11C	7067.8	5,750	0.182
	20C	7149.2	6,000	<0.001
	25C	7154.1	6,100	<0.001
	26C	7154.8	5,950	0.0135

	30C	7158.4	5,600	<0.001
	31C	7160.7	5,700	<0.001
	33C	7162.5	5,900	0.262
	34C	7163.2	6,000	<0.001
	35C	7164.2	6,200	<0.001
	39C	7,185.0	5,450	0.0967
	40C	7217.4	5,400	NOT TESTED
	41C	7222.3	5,450	NOT TESTED
1510	2D	6801.9	4,900	0.0444
	3D	6852.1	5,600	0.781
	9D	7125.6	6,400	2.26

Operations

All new wells are being operated in accordance with Fina Oil & Chemical's normal operating procedures.

Reservoir Surveillance

The reservoir surveillance dataset is currently being updated by recording pressure transient and cased-hole well log surveys on many of the same wells from which data were acquired during Budget Period I. Pressure transient tests (pressure buildups and pressure falloffs) are currently being recorded to monitor pressure trends in the infill areas, and cased-hole pulsed-neutron logs are being run to monitor changes in water saturation in the near-wellbore area.

Paleontologic Analysis

A total of 125 feet of the new core from three wells was analyzed by Fred Behnken of FHB Stratigraphic Services, Midland, Texas, for the purpose of documenting the faunal assemblage in the Clearfork reservoir. Analysis revealed the presence of several bryozoan genera, codiacean and coralline red algae, rugose corals, gastropods, crinoids, brachiopods of the composite type, foraminifera, and several genera of fusulinid foraminifera. Of particular interest is the occurrence of cyclostome bryozoa as the main frame-builder of the patch reefs in the Lower Clearfork. The bryozoa have erect, laminar and bifoliate growth forms, which appear to have formed an effective sediment baffle. These growth forms are massive and robust, indicating a moderate to high energy depositional environment. Six genera of cyclostome bryozoa were identified in these reefs. The reefs contain bryozoa both in growth position and as desegregated, overturned fragments floating in a muddy matrix. Core analysis reveals that the reefs themselves are non-porous and tight. Surrounding reef talus and reef debris aprons are, however, very porous and permeable, containing some of the highest permeability in the Clearfork.

Also of interest is the occurrence of two distinct populations of fusulinid foraminifera. Most common are larger (4-15 mm) Parafusulina spp. Fusulinids, present in shoals and deeper water sediments. Less common are smaller (0.15-1.5 mm) Schubertella spp. Fusulinids. These smaller forms appear to occur in more restricted environments of the lagoonal side of the reefs. Rather than the more seaward, open-shelf facies containing most of the larger forms. This difference could be a function of either physical sorting or ecological preference, either way it seems to be a good environmental indicator.

Deterministic

Recent deterministic simulations/reservoir modeling runs have yielded specific reservoir behavioral characteristics.

The North Robertson Glorietta - Clearfork reservoir models contain two distinct, but connected rock systems in each of the ten layers. The first system contains the higher permeability geologic layers (5-35 millidarcies) and the vertical hydraulic fractures (200 - 400 millidarcies) which run through the second system of low permeability matrix rock (0.1 millidarcies). The quantity, continuity, and reservoir quality (porosity, permeability, relative permeability, etc) of the higher permeability layers vary both areally and vertically. In general, these properties improve in a downward direction within the reservoir and vary in complex patterns laterally.
In the simulation reports, maps of reservoir conditions (pressure, saturations) have been provided for both rock systems for each layer at the end of the history period (12/96) and at the end of each prediction case (12/15). The exception to this is that maps for reservoir pressure were prepared only for one system since the two systems differ by only a few psi within each layer. The small differences in pressure indicate that the pressure communication between the two systems is good. However, lateral variations in the connectivity of the two systems is an important history match parameter. Due to the presence of shales or silty beds between model layers, inter-layer communication is poor. As can be seen in the maps, communication along the hydraulic fractures is excellent and along the higher permeability layers is good, whereas communication through the lower permeability matrix is very poor.

True fluid flow occurs almost entirely within the hydraulic fractures and the higher permeability layers. By the end of the prediction period, nearly all of the mobile oil has been swept from this system in the vicinity of the water injection wells (in layers which are completed). Oil remaining in the higher permeability layers around the production wells is on the order of 50 percent (SORW = 24 percent). A significant amount of mobile oil remains in the higher permeability layers, but under waterflood, recovery of this oil will require further infill drilling, selective recompletions, hydraulic fracturing, and production at high water cuts for an extended period of time.

The rate of field oil production and the ultimate oil recovery can be significantly increased for the higher permeability layers by miscible gas injection. Simulation of miscible gas injection scenarios with the current reservoir models will estimate the amount of these increases and provide sufficient data to determine the economic feasibility of this type of development.

The low permeability matrix contributes to reservoir productivity through expansion of fluids into the high permeability layers and hydraulic fractures. The reservoir quality of this matrix rock is very poor and the high capillary pressures result in high initial water saturations (generally greater than 65 percent). The oil in this rock is essentially immobile (SORW = 36 percent). A review of the oil saturation maps indicates that the maximum oil saturation changes in the low permeability layer at the end of predictions is only a few percent. Oil saturations decreased most in the vicinity of the production wells. This is <u>not</u> due to large amounts of oil moving from the low permeability matrix to the higher permeability layers or hydraulic fractures. It is rather due to shrinkage of the oil as gas comes out of solution as reservoir pressures decreased during history. Expansion of gas in the low permeability matrix resulted in the movement of gas and water to the higher permeability layers, not oil. The relative permeability to oil in the matrix rock remained at, or very close to, zero during the simulations.

The maps of change in water saturation for the low permeability matrix are very similar in character to the maps of reservoir pressure. As pressures decreased in the vicinity of production wells (and their hydraulic fractures) gas evolved in the matrix rock. This gas displaced water into the higher permeability system. (This explains the need for aquifer functions within the reservoir in previous single-porosity simulations.) Some of the gas in the matrix also expended into the higher permeability system, contributing to the high produced gas-oil ratios observed during history prior to water injection. As water injection repressured the reservoir, much of the gas remaining in the low permeability matrix went back into solution in the oil. However, since a significant amount of gas had moved into the higher permeability system, the oil did not swell back to its original volume and hence the decrease in oil saturation by a few percent relative to its original volume.

Little injection water has entered the low permeability matrix rock (only enough as required to maintain pressure equilibrium between the higher permeability and low permeability systems). No oil is being displaced from the matrix by water injection. Although the potential effects of gravity drainage and imbibition are not well known at this time, it would be expected that injected gas would also remain primarily in the higher permeability layers. Forecasts of oil recovery from miscible gas injection should not count on significant contributions from the low permeability matrix until further investigations are performed.

The physical characteristics of the two reservoir systems are primary history match parameters in the North Robertson simulation studies. In particular, the pore volumes, permeabilities, capillary pressures (initial saturation distributions), and relative permeabilities have significant control over reservoir behavior. These parameters were tuned to yield a good match of historical well performance and there is a high degree of confidence in their calibrated values.

INITIAL FLUIDS IN PLACE

OIL	37530. MSTB
GAS	16756. MMSCF
WATER	67401. MSTB
HPVOL	47111. RESB

TABLE 2
CASE RESULTS BY WELL GROUP - AREAL MODEL SIMULATIONS CLEARFORK RESERVOIR, NORTH ROBERTSON UNIT, SECTION 327

CASE	END OF CASE dd/mm/yy	days	CUMULATIVE PRODUCTION AT END OF CASE: OIL MSTB	OIL REC. percent	GAS MMSCF	GOR SCF/STB	WATER MSTB	WAT.CUT percent
HISTORY								
GC 1			1839	4.9	2739	1489	596	24.5
GC 2			1225	3.3	625	510	2360	65.8
GC 3			46	0.1	16		101	
TOTAL	31/12/96	14945	3109	8.3	3380	1087	3057	49.6
CASE 1								
GC 1			1839	4.9	2739	1489	596	24.5
GC 2			2513	6.7	1111	442	10607	80.8
GC 3			910	2.4	353		6483	
TOTAL	31/12/15	21884	5263	14	4203	799	17686	77.1

CASE 2								
GC 1			1839	4.9	2739	1489	596	24.5
GC 2			2252	6	1022	454	11208	83.3
GC 3			2097	5.6	807	385	16826	88.9
TOTAL	31/12/15	21884	6188	16.5	4567	738	28630	82.2
CASE 3								
GC 1			1839	4.9	2739	1489	596	24.5
GC 2			1385	3.7	686	495	2898	67.7
GC 3			2286	6.1	1267	554	34052	93.7
TOTAL	31/12/15	21884	5510	14.7	4692	852	37546	87.2

TABLE 1
CASE DESCRIPTIONS - AREAL MODEL SIMULATIONS
CLEARFORK RESERVOIR, NORTH ROBERTSON UNIT, SECTION 327

CASE 1

Continued historical production / injection scheme.
Twenty-two production wells with calibrated productivity indices. Pumps: Min. FBHP= 100. psia
Production wells: sixteen 20-acre and six 10-acre wells.
Production wells allowed to produce at full potential based on FBHP constraints.
Production wells shutin at WCUT = 99. Percent. No workovers.
Twenty-seven water injection wells with calibrated injectivity indices. Max. FBHP=3200 psia
Water injection wells: twenty-five 40-acre and two 10-acre wells.
Water injection wells allowed to inject at full potential based on FBHP constraints.
Simulation terminated at 31/12/15.

CASE 2

Line-drive water injection with infill drilling. Ten-acre spacing.
Same as CASE 1 except:
Fourteen new production wells completed from 01/98 to 03/99.
Production wells: sixteen 20-acre and twenty 10-acre wells.
Calibrated productivity indices of new production wells derived from values at offset wells.
Eighteen new water injection wells completed from 01/98 to 03/99.
Water injection wells: twenty-five 40-acre and twenty 10-acre wells.
Calibrated injectivity indices of new and converted injection wells derived from values at offset well
Frac jobs performed at each new and converted well at time of completion.

CASE 3

Five-spot water injection with infill drilling. Ten-acre spacing.
Same as CASE 1 except:
Forty new production wells completed from 01/98 to 03/99.
Production wells: forty 10-acre wells.
Calibrated productivity indices of new production wells derived from values at offset wells.
Sixteen existing wells converted to water injection from 01/98 to 03/99.
Water injection wells: twenty-five 40-acre and sixteen 20-acre wells.

Calibrated injectivity indices of converted injection wells derived from values at offset wells.

Frac jobs performed at each new and converted well at time of completion.

PUBLICATIONS AND PRESENTATIONS - *TASK II.4.3*

Published Papers and Professional Meeting Presentations:

1997 Annual DOE/BDM International Reservoir Characterization Technical Conference, March 2-4, 1997, Houston, TX.

- Oral presentation and poster session on project material
- "Improved Characterization of Reservoir Behavior by Integration of Reservoir Performance Data and Rock Type Distributions."

Oklahoma Geological Society Circular, *Platform Carbonates in the Southern Mid-Continent*, (in press), K.S. Johnson, March 1997.

- "Environments of Deposition for the Clear Fork and Glorieta Formations, North Robertson Unit, Gaines County, Texas."

1997 DOE/BDM Annual Contractor Review Meeting, June 16-20, Houston, TX.

- Oral presentation

SECTION 2

EXHIBITS

FORMATION WATER ANALYSES

Fina Oil and Chemical Company
North Robertson Unit
Clearfork Formation
Gaines County, Texas

Component	grams / liter
NaC1	49.14
CaC12+2h20	34.85
MgC12+6H20	31.79
KCl	13.04
Na2S04	3.00
NaHC03	1.50

SULFATE SATURATED BRINE

Na2S04	23.98
Cas04+2H20	2.21
SrS04	0.11

SUMMARY OF UNSTEADY-STATE GAS-OIL RELATIVE PERMEABILITY TESTS

Fina Oil and Chemical
Well 3533
North Robertson Unit
Clearfork Formation
Gaines County, Texas

Sample Number	Well	Depth, feet	Specific Permeability to Air, md.	Porosity, percent	Initial Conditions Water Saturation, percent	Initial Conditions Effective Permeability to Oil, md.	Gas Saturation Kg/Ko=1.0, percent
1A	1509	6237.8	16.5	13.8	23.7	2.6	9.4
3A	1509	6349.9	3.57	9.88	12.6	1.09	17.9
6B	3533	6400.9	4.34	10.1	9.2	0.74	9.7
7B	3533	6401.9	19.8	13.5	17.3	4.57	21.5
8B	3533	6402.2	1.23	6.8	27.2	0.448	3.5*
10B	3533	6404.1	2.46	7.87	21.1	1	8.1*
18B	3533	6422.9	4.76	10.7	29.4	1.34	10.0
21B	3533	6427.9	34.3	13.7	12.3	17.1	8.8
22B	3533	6428.1	16.3	10.7	24.8	7.75	17.2
24B	3533	6951.7	16.2	11.8	24.4	11.3	12.0
25B	3533	6952.1	29.1	11.6	26.4	16.3	16.2
26B	3533	6952.9	4.31	15.4	27.6	6.33	10.0
34B	3533	7191.2	13.1	9.3	22.3	10.8	13.0
3D	1510	6852.1	2.45	11.5	21.7	0.589	13.5
9D	1510	7125.6	2.94	6.88	32.3	1.53	8.6

*Insufficient production for relative permeability calculation. Gas saturation is an end point value

SUMMARY OF UNSTEADY-STATE GAS-OIL RELATIVE PERMEABILITY TESTS

Fina Oil and Chemical
Well 3533
North Robertson Unit
Clearfork Formation
Gaines County, Texas

Sample Number	Well	Depth, feet	Specific Permeability to Air, md.	Porosity, percent	Initial Conditions Water Saturation, percent	Initial Conditions Effective Permeability to Oil, md.	Endpoint Oil Permeability, md	Final Gas Saturation at Oil Floodout, percent
1A	1509	6437.8	15.5	13.8	23.7	2.6	1.86	12.8
3A	1509	6349.9	3.57	9.88	12.6	1.09	Sample plugged	
6B	3533	6400.9	4.34	10.1	9.2	0.74	0.269	10.7
7B	3533	6401.9	19.8	13.5	17.3	4.57	3.35	9.3
8B	3533	6402.2	1.23	6.8	27.2	0.448	0.339	0.0
10B	3533	6404.1	2.46	7.87	21.1	1.00	0.167	6.9
18B	3533	6422.9	4.76	10.7	29.4	1.34	0.724	12.6
21B	3433	6427.9	34.3	13.7	12.3	17.1	10.1	8.3
22B	3533	6427.1	16.3	10.7	24.8	7.75	6.56	17.8
24B	3533	6951.7	16.2	11.8	24.4	11.3	4.47	14.1
25B	3533	6952.1	29.1	11.6	26.4	16.3	10.2	13.8
26B	3533	6952.9	4.31	15.4	27.6	6.33	1.26	14.2
34B	3533	7191.2	13.1	9.3	22.3	10.8	3.88	20.0
3D	1510	6852.10	2.45	11.5	21.7	0.589	0.412	13.1
9D	1510	7125.60	2.94	6.88	32.3	1.53	0.691	7.1

SUMMARY OF STEADY-STATE WATER-OIL RELATIVE PERMEABILITY TESTS

Multiple Wells
North Robertson Unit
Gaines County, Texas

Sample Number	Well Number	Depth, feet	Air Perm, md	Porosity, percent	Initial Conditions: Water Saturation, %PV	Initial Conditions: Perm to Oil, md	Terminal Conditons: Oil Saturation, %PV	Terminal Conditons: Perm to Water, md	Terminal Conditons: Relative Perm to Water*, fraction	Oil Recovered: percent pore volume	Oil Recovered: percent oil-in-place
Native State with Crude Oil at 110F											
** 1A	1509	6,347.8	16.5	14.4	23.7	2.25	32.8	0.356	0.158	43.5	57.0
21B	3533	6,427.9	31.9	14.2	12.3	11.5	26.0	4.28	0.372	61.7	70.4
									Average =	52.6	63.7
Clean State with Laboratory Oil.											
1A	1509	6,347.8	16.5	14.4	15.0	5.06	22.1	2.42	0.478	62.9	74.0

*Relative to oil permeability at initial water saturation.

** Sample plugged during testing.

SUMMARY OF STEADY-STATE WATER-OIL RELATIVE PERMEABILITY TESTS

Fina Oil and Chemical Company
Multiple Wells
North Robertson Unit
Gaines County, Texas

mple mber	Well No.	Depth, feet	Perm, md	Porosity, percent	Sat., %PV	Perm to Water, md	Sat., %PV	Perm to Oil, md	Perm to Water*,fraction	percent pore volume
Native State with Crude Oil at 110F										
	1509	6,347.8	16.5	14.4	32.8	0.356	36.5	0.104	0.0462	30.7
	3533	6,427.9	31.9	14.2	26.0	4.28	37.3	3.38	0.294	36.7
									Average =	33.7
Clean State with Laboratory Oil										
1A	1509	6,347.8	16.5	14.4	22.1	2.42	29.0	1.23	0.243	48.9

ve to oil permeability at initial water saturation.

mple plugged during testing.

SUMMARY OF WATER-OIL CENTRIFUGE CAPILLARY PRESSURE TEST RESULTS

Fina Oil and Chemical Company
Multiple Wells
North Robertson Unit
Gaines County, Texas

mple mber	Well Number	Depth, feet	Air Perm, md.	Porosity, percent	Cap Pres, psi	Average Water Saturation, percent pore volume	Hassler-Brunner Water Saturation percent pore volume
3A	1509	6,349.9	2.78	10.3	0.00	32.6	32.6
					0.99	37.9	42.6
					2.22	42.3	55.8
					4.99	54.7	70.8
					11.23	67.1	75.9
					25.53	72.4	79.9
					57.53	76.8	83.3
					130.15	81.2	86.4
					293.9	85.6	89.1
4A	1509	6,350.2	0.698	8.9	0.00	6.9	6.9
					1.02	15.8	23.2
					2.29	21.7	36.4
					5.15	30.6	50.7
					11.59	46.3	60.8
					26.33	57.2	65.4
					59.34	62.1	66.8
					134.5	65.1	67.1
					303.15	66.1	67.2
6B	3533	6,400.9	4.61	10.9	0.00	39.8	39.8
					1.01	47.8	49.2
					2.28	47.8	53.9
					5.14	54.3	60.1
					11.56	59.9	66.5
					26.27	64.7	72.4
					59.2	72.0	77.4
					133.92	76.0	81.5
					302.4	76.8	84.6

WATER-OIL CENTRIFUGE CAPILLARY PRESSURE TEST RESULTS

Fina Oil and Chemical Company
Multiple Wells
North Robertson Unit
Gaines County, Texas

ample umber	Well Number	Depth, feet	Air Permeability, md.	Porosity, percent	Capillary Pressure, psi	Average Water Saturation, percent pore volume	Hassler-Brunner Water Saturation percent pore volume
8B	3533	6,402.2	0.998	7.3	0.00	21.3	21.3
					1.01	26.1	40.0
					2.27	38.2	46.2
					5.11	45.5	52.4
					11.5	57.6	58.6
					26.14	64.8	64.9
					58.71	67.2	71.1
					133.55	69.7	77.4
					300.48	75.7	83.6
10B	3533	6,404.1	2.06	8.1	0.00	5.3	5.3
					1.00	11.9	18.8
					2.24	18.5	28.7
					5.05	26.3	37.7
					11.35	38.4	46.2
					25.79	46.1	54.9
					57.94	53.8	63.5
					131.79	59.3	72.3
					296.54	66.0	81.0
11C	3319	7,067.8	fractured	10.4	0.00	13.2	13.2
					1.01	20.0	22.7
					2.27	21.7	34.8
					5.10	30.2	46.1
					11.47	45.5	55.5
					26.07	60.0	62.7
					58.76	64.2	68.0
					132.93	65.9	71.8
					300.17	68.5	74.4

SUMMARY OF HYDROSTATIC PORE VOLUME COMPRESSIBILITY TEST DATA

Fina Oil and Chemical Company
Multiple Wells
North Robertson Unit
Clearfork Formation
Gaines County, Texas

ample umber	Well	Depth, feet	Specific Permeability, to Air*, md.	Helium Porosity*, percent	Pore Volume Reductio n, Percent	Pore Volume Compressibility**, vol/vol/psi	Confining Pressure, psi
28A	1509	7188.6	0.178	5.70	4.46	8.18	3,500
					6.49	4.79	7,500
34A	1509	7219.1	0.0865	10.8	1.93	2.66	3,500
					2.36	1.25	7,500
35A	1509	7220.1	0.0355	7.10	3.4	6.31	3,500
					5.09	3.65	7,500
26C	3319	7154.8	2.27	3.10	10.0	19.1	3,500
					15.0	10.7	7,500
39C	3319	7185.0	0.504	10.9	7.40	13.9	3,500
					10.8	8.0	7,500
2D	1510	6801.9	0.194	4.60	4.93	9.0	3,500
					7.43	4.95	7,500

*Measured at standard conditions of 400 psi overburden.
** Units of (1E-06)

HYDROSTATIC PORE VOLUME COMPRESSIBILITY TEST RESULTS

Fina Oil and Chemical Company
Well 1509
North Robertson Unit
Clearfork Formation
Gaines County, Texas

ample umber	Well	Depth, feet	Specific Permeability to Air*, md.	Helium Porosity*, %	Confining Pres., psi	Pore Volume Reduction, Percent	Pore Volume Compressibility**, vol/vol/psi
28A	1509	7,188.6	0.178	5.70	500	0.00	32.9
					1,000	1.21	20.0
					3,500	4.46	8.18
					4,500	4.82	6.85
					5,500	5.26	5.95
					6,500	6.21	5.29
					7,500	6.49	4.79

*Measured at standard conditions of 400 psi overburden.
** Units of (1E-06)

HYDROSTATIC PORE VOLUME COMPRESSIBILITY TEST RESULTS

Fina Oil and Chemical Company
Well 1509
North Robertson Unit
Clearfork Formation
Gaines County, Texas

ample umber	Well	Depth, feet	Specific Perm. to Air*, md.	Helium Porosity*, percent	Confining Pres. psi	Pore Volume Reduction, Percent	Pore Volume Compressibility**, vol/vol/psi
34A	1509	7,219.10	0.0865	10.8	500	0.00	18.3
					1,000	0.54	9.2
					3,500	1.93	2.66
					4,500	2.03	2.08
					5,500	2.24	1.70
					6,500	2.35	1.44
					7,500	2.36	1.25

*Measured at standard conditions of 400 psi overburden.
** Units of (1E-06)

HYDROSTATIC PORE VOLUME COMPRESSIBILITY TEST RESULTS

Fina Oil and Chemical Company
Well 1509
North Robertson Unit
Clearfork Formation
Gaines County, Texas

ample umber	Well	Depth, feet	Specific Perm to Air*, md.	Helium Porosity*, percent	Confining Pressure, psi	Pore Volume Reduction, Percent	Pore Volume Compressibility**, vol/vol/psi
35A	1509	7,220.10	0.0355	7.10	500	0.00	25.8
					1,000	1.13	15.6
					3,500	3.40	6.31
					4,500	3.79	5.26
					5,500	4.13	4.56
					6,500	4.78	4.05
					7,500	5.09	3.65

*Measured at standard conditions of 400 psi overburden.
** Units of (1E-06)

HYDROSTATIC PORE VOLUME COMPRESSIBILITY TEST RESULTS

Fina Oil and Chemical Company
Well 1509
North Robertson Unit
Clearfork Formation
Gaines County, Texas

ample umber	Well	Depth, feet	Specific Perm to Air*, md.	Helium Porosity*, percent	Confining Pressure, psi	Pore Volume Reduction, Percent	Pore Volume Compressibility**, vol/vol/psi
[illegible]	1509	7,220.10	0.0355	7.10	500	0.00	25.8
					1,000	1.13	15.6
					3,500	3.40	6.31
					4,500	3.79	5.26
					5,500	4.13	4.56
					6,500	4.78	4.05
					7,500	5.09	3.65

*Measured at standard conditions of 400 psi overburden.
** Units of (1E-06)

SUMMARY OF WATER-OIL CENTRIFUGE CAPILLARY PRESSURE TEST RESULTS

Fina Oil and Chemical Company
Multiple Wells
North Robertson Unit
Gaines County, Texas

ample umber	Well Number	Depth, feet	Air Perm md.	Porosity, percent	Capillary Pressure, psi	Average Water Saturation, percent pore volume	Hassler-Brunner Water Saturation percent pore volume
14A	1509	7,068.4	1.09	5.9	0.00	33.7	33.7
					1.00	41.2	45.0
					2.26	44.2	51.0
					5.07	48.8	57.4
					11.42	57.8	63.4
					25.94	63.8	68.7
					58.46	68.3	73.1
					132.26	71.4	76.7
					298.67	72.9	79.4
28B	3533	7,135.9	2.78	7.4	0.00	20.1	20.1
					1.01	28.6	37.5
					2.28	39.5	49.0
					5.13	46.7	57.7
					11.54	55.2	63.7
					26.22	61.3	67.7
					59.10	63.7	70.3
					133.70	68.5	72.1
					301.91	70.9	73.3
33C	3319	7,162.5	3.57	13.1	0.00	17.0	17.0
					1.02	33.0	39.8
					2.29	37.0	45.8
					5.15	44.4	50.1
					11.58	49.0	53.4
					26.31	53.7	56.7
					59.29	56.4	60.0
					134.14	59.1	63.2
					302.90	60.4	66.5

HYDROSTATIC PORE VOLUME COMPRESSIBILITY TEST RESULTS

Fina Oil and Chemical Company
Well 3319
North Robertson Unit
Clearfork Formation
Gaines County, Texas

ample umber	Well	Depth, feet	Specific Perm. to Air*, md.	Helium Porosity*, percent	Confining Pressure, psi	Pore Volume Reduction, Percent	Pore Volume Compressibility**, vol/vol/psi
39C	3319	7,185.00	0.504	10.9	500	0.00	58.7
					1,000	1.29	35.0
					3,500	1.94	13.9
					4,500	2.26	11.6
					5,500	2.59	10.0
					6,500	2.91	8.87
					7,500	3.24	8.00

*Measured at standard conditions of 400 psi overburden.

** Units of (1E-06)

HYDROSTATIC PORE VOLUME COMPRESSIBILITY TEST RESULTS

Fina Oil and Chemical Company
Well 1510
North Robertson Unit
Clearfork Formation
Gaines County, Texas

ample umber	Well	Depth, feet	Specific Perm. to Air*, md.	Helium Porosity *, percent	Confining Pressure, psi	Pore Volume Reduction, Percent	Pore Volume Compressibility**, vol/vol/psi
2D	1510	6,801.90	0.194	4.60	500	0.00	42.2
					1,000	1.82	24.3
					3,500	4.93	9.00
					4,500	5.72	7.39
					5,500	6.25	6.3
					6,500	6.84	5.54
					7,500	7.43	4.95

*Measured at standard conditions of 400 psi overburden.
** Units of (1E-06)