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Validation of Gravity-dominated Relative Permeability and Residual Oil Saturation in a Giant Oil Reservoir

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Abstract

Gravity drainage is normally characterized as a slow but efficient process, leading to a low remaining oil saturation. If the reservoir has a large oil column and a high vertical permeability, then efficient recovery may be achieved through the gravity drainage process that accompanies a stable gas cap expansion. An extensive experimental program was conducted to characterize the flow properties of the gravity drainage process where oil is displaced by gas in the presence of an initial water saturation. The experiments described here were designed to give endpoint saturations, oil relative permeabilities, and gas relative permeabilities for the gas-displacing-oil gravity drainage situation. No single test provides all of these parameters required for performance prediction. Long core gravity drainage tests, as well as porous plate and centrifuge tests, were performed at simulated reservoir conditions. The long core drainage tests were conducted in a vertical coreflood apparatus in which in-situ oil and water distributions were monitored regularly using both x-ray and microwave scanning systems.

The experimental results support the following conclusions with regard to high permeability, unconsolidated sands:

- **Residual oil saturation to the gravity drainage process (S_{org}) is low, 3-10% and is somewhat insensitive to rock properties. This level of saturation is achieved through film drainage and may require considerable time and suitable conditions (oil column height and fluid density differences).**
- **S_{org} is not sensitive to fluid properties such as viscosity, interfacial tensions, and spreading coefficient for the limited systems studied.**
- **S_{org} does not depend on initial water saturation within a reasonable range.**
- **k_{ro} and k_{rg} depend on rock properties.**
- **Conventional gas flood tests give higher S_{org} (average 30%), even at high volume (1000 PV) and/or low rate gas injection, and do not represent the gravity drainage process.**

These laboratory findings were validated by a subsequent coring operation, using a low invasion water-based mud, in the secondary gas cap of the Ubit field, offshore Nigeria, that had been in production for twenty-five years. The residual oil saturations to gravity drainage found in the secondary gas cap agreed well with laboratory results. However, the observed S_{org} was not achieved in the simulation of the field history when detailed geological description and the lab measured k_{ro} was used. Adjustment of k_{ro} by an order of magnitude near the S_{org} was necessary to match the S_{org} distribution observed in the secondary gas cap. It was found that the low k_{ro} close to S_{org} was an artifact due to capillary end effects, not fully accounted for in initial modeling. Subsequent lab tests were designed to generate appropriate data for reservoir management. Adjustment of k_{ro} was justified when data were reanalyzed, taking P_c into consideration, and bringing laboratory measurements, field observations, and reservoir simulation into complete agreement.

Introduction

It has been shown by Haldorsen [1] that the gravity drainage mechanism is very time-effective, and can yield high displacement efficiencies, in homogeneous sands, of 60-70% (OOIP). Haldorsen validated laboratory measurements of low residual oil saturations using logging data of the reservoir above the advancing gas-oil contact in a reservoir produced under gravity drainage.

Dumore and Schols [2] recognized the importance of connate water in gravity drainage. The oil recovery increased and the relative permeability increased with connate water present. The spreading of oil on the initial water saturation film, in the presence of gas enabled film flow of the oil to a low residual.

Vizika and Lombard [3] studied the effects of wettability and the spreading nature of the fluid system in three-phase gravity drainage. The best recovery was obtained in systems with a spreading oil film, and in water-wet or fractionally wet systems. In water wet systems, with oil that maintains a positive spreading coefficient, the low residuals have been confirmed in numerous laboratory studies using both micromodels and core material[4,5]. Three phase relative permeabilities for gravity drainage systems with different spreading coefficients have been measured [6].

The Ubit Field

Ubit field is a giant oil field, located 35 miles offshore Nigeria [7]. The field was discovered in 1968 and brought on-stream in 1970. Oil volumes were 2.1 billion barrels STOIIP. The reservoir has a closure of 15,000 acres, with an oil column of 160', a gas cap of 50'-550', and a small aquifer. Oil gravity is 37° API. The recovery mechanism is gravity drainage under a slowly expanding gas cap.

Ubit's structure is a large east-west trending anticline bounded to the north, west and south by two large, intersecting growth faults. Both are downthrown to the south. The structure gently dips to the east. Hydrocarbon reserves are found at depths of approximately one mile in the Miocene Biafra Sand member of the Agbada Formation. Reservoir sands are unconsolidated sands and shales of a prograding system of lower delta plain, shallow marine and marine origin. The overlying deep marine shales of the Pliocene Qua Iboe member form the reservoir seal. 3500' of prograding stratigraphic section cuts through the oil column. Fluid contacts are essentially flat. Non-sealing faults have provided the mechanism for fluid and pressure communication between blocks.

The major facies types representing Ubit's depositional system turbidites, debris flow, tidal channel, lagoonal, upper and lower shoreface sands and shales. Excellent quality, fine-grained, well-sorted shoreface sands comprise approximately sixty-six per cent of the oil column. Grain size is the primary controlling element in property relationships in Ubit's generally fine-grained well-sorted depositional system.

Ubit is currently under extensive integrated reservoir management. A horizontal well re-development program has been in place for several years. Reservoir management has resulted in an increase of recoverable reserves by a half billion barrels and a production uplift of 110 MBD. To date, 37 horizontal wells have been drilled. Key reservoir management strategies were applied to maximize performance and ultimate recoveries. They included implementing horizontal well drilling, full-field, full-life reservoir simulation results defining optimal well placement / timing, balancing a non-uniform areal oil column, maintaining stable gas cap movement and pressure throughout, establishment of a field rate plateau, and minimizing free gas production.

For 25 years, Ubit averaged only 30 MBD with high gas-oil ratio. Gas breakthrough from conventional directional wells was problematic. Previous reservoir interpretations described the chaotic nature and poor quality reservoir of the eastern two-thirds of the reservoir. Poor historical production performance seemed to confirm these interpretations. A new horizontal-layered, hydraulic-focused geologic model combined with advanced reservoir simulation yielded a substantially improved interpretation. The new characterization, which integrated 3-D seismic, cores, logs, and historical production data revealed that the reservoir is a prograding deltaic-shallow marine system which had been tectonically disturbed. Downslope movement of the youngest sand sequences resulted in large scale slumping and block sliding affecting the eastern portion of the field. Reservoir quality is good to excellent in these unconsolidated sediments.

Appropriate technology application through applied reservoir management has meant that this old field is now producing an all-time high of 140 MBD, with ultimate recoveries expected to exceed 1 billion barrels.

Significance of the Gravity Drainage Process

Gravity drainage is normally characterized as a slow but efficient process. If the reservoir has a large oil column or a high vertical permeability, then efficient recovery may be achieved through the gravity drainage process. In the Ubit reservoir studied here, the recovery mechanism is natural gas cap expansion, a gravity-dominated process. The experiments performed for this reservoir were designed to give endpoint saturation, oil relative permeability, and gas relative permeability for the gas-displacing-oil gravity drainage situation. No single test provides all of these parameters required for performance prediction.

The displacement of oil by gas during the process of gas cap expansion is an example of gravity drainage.

This is a different physical process from oil displacement by gas injection (illustrated in Figure 1) as typically performed in laboratories for determination of relative permeabilities. In gas injection, oil bypassing and trapping events occur. Once hydraulic connectivity in the oil phase is lost, it may not be economically feasible to recover that oil. Remaining oil saturations can be large. In gravity drainage, the oil is either recovered by an initial free-fall process or through film drainage and capillary action. The gravity drainage process naturally maintains connectivity in the oil phase until oil films can no longer be sustained. The process stops when equilibrium is reached between gravitational forces and capillary retention forces. Since capillary pressure is a function of the height above the gas-oil contact, the residual oil saturation will also be a function of height in the reservoir. For the reservoir studied here, the transition region turned out to be very thin, due to the capillary pressure behavior of high permeability sand.

Gravity drainage can be simulated by unsteady displacements in long core experiments, or by the centrifuge method [8,9]. The centrifuge technique simulates gravity drainage, but experimental times are much shorter, since the gravitational constant can be varied with rotational speed. We are not concerned with the artificial elevation of the gravitational constant produced by the centrifuge, but the duplication of forces experienced in gravity drainage at different locations in the reservoir with respect to the gas-oil contact. It is essential to carry out such tests where core plugs are confined under simulated reservoir stress, especially for unconsolidated samples. Centrifuge tests at near reservoir temperatures and using reservoir crude oil are also desirable to preserve properties effecting the process. However, the effect of fluid pressure can only be duplicated in vertically oriented long core tests. Cores for free gravity drainage experiments have to be long enough to cover the thickness of the transition zone, or a differential pressure between top and bottom of the core must be applied to overcome capillary holdup (end effects).

Comparison of Gravity Drainage and Viscous Dominated Gasflood Experiments

A distinction should be made between recoveries by processes where density contrast and gravity control the flood front and by those where gravitational forces play a less significant role in ultimate fluid distribution. Figure 2 shows residual oil saturation data for gasflooded samples from Ubit and several similar reservoirs. Note the relatively high average residual saturation of about 29.3%, with no value below 12%. In contrast, Figure 2 also displays available gravity drainage endpoint saturations, defined as the saturation at which $k_{ro} = 10^{-6}$, for highly permeability sandstone samples, indicating a mean residual saturation of 7.1%. A tabular summary of Ubit gravity drainage tests is shown in Table 1. Although the number of samples is still small, Ubit gravity drainage data has been collected throughout the field and from multiple facies types.

Literature data was collected in Table 2 to supplement internal measurements on gravity stable processes. The results from 20 laboratory experiments, mostly on outcrop sandstone cores showing an average residual oil saturation of 6.3%. Porosities, permeabilities, and initial water saturations varied from 13-35%, 100-3500 md, and 2-35% respectively in these tests. This literature data was acquired on sandstones very different from the unconsolidated reservoir sands discussed in this paper. Nonetheless, these data are important in that they establish that data acquired on unconsolidated cores are consistent with expectations of gravity drainage recovery efficiency.

It should be stated that even in a field producing under slow gas cap expansion, in certain areas, viscous forces dominate. These areas may include the near wellbore region, areas in which coning or fingering occurs (e.g. a thin oil column), and areas of the reservoir in which there is fast movement of the gas/oil contact (e.g. heterogeneous reservoirs).

Experimental Study

Coring, Preservation, Sampling, and Saturation Measurements

The cores used in this study were all poorly consolidated sandstones. Most cores were taken with oil-based drilling mud; some were taken with water-based mud. The cores and fiberglass core barrel were cut into three-foot sections at the well site. A six-inch portion of each section was preserved for fluid saturation measurements. These portions were frozen at the well site and transported to a local laboratory for Dean-Stark or retort analysis. The remainder of the cores, in 2.5-foot sections, along with some of the plugs from the six-inch portions, were preserved and packaged carefully at the well site to maintain their integrity for the experimental study.

SCAL Sample Selection and Plugging

In the laboratory, plugs were cut from frozen cores, using liquid nitrogen as a cutting fluid. Plugs were packaged in foil with screens on each end, wrapped in plastic, and stored in a freezer. Plugs were checked using a CT scanner to ascertain their integrity.

Fluid Saturation Measurements

Vertical plugs were taken from each six-inch preserved section. Dean-Stark measurements were made with appropriate quality control. The density of the oil was determined from oil centrifuged from selected plugs. The Dean-Stark water saturations were corrected for salinity. Fluid saturations were adjusted using the appropriate formation volume factor. When low invasion oil-based mud was used in coring, the water saturations measured were representative of the initial reservoir saturation. Conversely, when low invasion water-based mud was used, the measured oil saturation in the secondary gas cap was characteristic of the residual oil saturation, S_{org}.

Types of P_c and k_r Measurements

Several types of capillary pressure and relative permeability measurements were made on the cores under study to characterize the gravity drainage process. These included:

1. Long core experiments to determine residual saturations and gas permeability.
2. Relative permeability tests using centrifuge method.
3. Capillary pressure tests using both porous plate and centrifuge methods.
4. Vertically oriented gasflood tests at very slow displacement rates.

All tests were conducted at a net overburden pressure and near reservoir temperature. Stock tank crude oil from the reservoir was filtered, and sometimes blended with a light hydrocarbon to match the viscosity of the down-hole live fluid. Brine was synthesized to match the composition of produced brine. All tests were conducted with cores at representative initial water saturation, established either by preservation of the original S_{wi} or by restoration to S_{wi} using porous plate desaturation. Some tests were conducted on wettability restored cores. These cores were first cleaned by miscible flooding with a sequence of solvents, and restored to S_{wi}, and aged with crude oil at near reservoir temperature.

Gravity Drainage Experiments

Long Core Relative Permeability Apparatus

Gravity drainage experiments were made using a vertical coreflood apparatus. The design of the equipment is shown in Figure 3. The apparatus uses both microwave and x-ray attenuation to monitor the water and oil saturation distributions during the experiment. It is also equipped with both oil-wet and water-wet porous plates at the outlet end of the core, to prevent gas breakthrough, to accommodate capillary pressure measurements, and to establish more uniform saturations along the core.

The composite core used in the long core experiments was a two inch diameter, ten-inch long shoreface sand, whose porosity varied from 31 to 34% and whose air permeability varied from 2300 to 4200 md (Table 4). The core was allowed to imbibe brine, frozen, and shrink-wrapped in Teflon, with stainless steel screens on each end to prevent sand production.

The brine used in establishing S_{wi} was synthetic field brine. The oil used was stock tank crude oil from the field studied, blended with petroleum ether (16%) to have a viscosity of 1.12 cp. at 180 °F. The core was flooded with brine, then the initial water saturation was established by a porous plate method in an oil-displacing-water system.

A net confining stress of 2000 psi annulus pressure was applied to the core. This pressure ensures capillary contact between the segments of the core. The temperature of the core holder was increased to 170 °F. Gas pressure (90 psi) was applied to the top and bottom of the core so that the net differential pressure was zero. Experiments were monitored with x-ray and microwave scanning. The operating conditions for the x-ray and microwave scans are shown in Table 3.

To begin the gravity drainage experiment, a bypass valve on the bottom of the core holder head was opened. The oil drained freely under a constant backpressure, and was captured in a closed vessel and weighed automatically. When free drainage slowed and virtually stopped (< 0.1 g/day), drainage was continued through a 15 bar oil wet porous plate, with an applied differential pressure of 2.5 psi. Again, the oil produced was captured under system pressure and weighed. After drainage had slowed (< 0.1 g/day) the differential pressure was increased to 4 psi.

A novel method for measuring k_{rg} in a gravity stable test using a long core was adopted. It required development of a modified core holder head to include a bypass valve permitting fluid flow through a core during an experiment. This head allows one to measure k_{rg} at various oil saturations during the course of the experiment. During capillary desaturation, drainage was periodically interrupted in order to make gas permeability measurements. The bypass valve was opened, and gas flowed briefly through the core (1-10 cc/min). Differential pressures were measured between the top and bottom of the core, and the relative permeability to gas was calculated. Actual oil saturations were determined afterward, when the x-ray and microwave signals were calibrated.

After drainage from capillary desaturation had virtually stopped (< 0.1 g/day), the core was removed from the core holder. It was subdivided into four pieces, wrapped in tin sleeves, with stainless steel end screens. Fluid saturations in each piece were measured using a Dean Stark apparatus. Porosity and air permeability were measured for each piece. The results of these measurements are reported in Table 4 for a Ubit long core experiment.

The four core segments were reassembled in their previous arrangement. Endpoint scans were made of x-ray and microwave intensities as the core was miscibly flooded successively with brine, methanol, air, and crude oil. The endpoint x-ray scans are shown in Figure 4. The corresponding microwave scans are shown in Figure 5.

Centrifuge Experiments

Capillary pressure and relative permeability measurements by the centrifuge method were conducted on core plugs from rocks similar to those used in the long core experiments. Importantly for unconsolidated samples, the centrifuge experiments were conducted at near reservoir conditions of confining stress and temperature [9,10]. The method used included:

a) Primary oil-brine drainage P_c measurements in which S_{wi} values were attained.

b) Air-oil drainage P_c measurements at incrementally increasing centrifuge speeds in which the residual oil saturations were determined.

c) Air-oil drainage k_r measurements at a single high centrifuge speed (high Dombrowski-Brownell [11] number $N_{DB}=10^{-6}-10^{-3}$), in which the residual oil saturations were re-determined.

d) Single point gas permeability measurements when the core plug was removed from the centrifuge at the end of the experiment.

e) Basic rock property measurements on the samples.

f) Use of a coreflood simulator to correct the k_r determinations for end effects using the P_c measurements.

Centrifuge data collected at too low a speed must be corrected for capillary end effects. Centrifuge experiments run at high speeds produce more representative results.

Capillary Pressure Test @ S_{wi}

Gas-oil capillary pressure tests may be conducted by oil-wet porous plate or by centrifuge tests to characterize capillary pressure and residual oil saturations. Figure 6 shows a typical oil-water capillary pressure curve and gas-oil P_c at S_{wi} from centrifuge. Reliable porous plate P_c curves, or centrifuge gas-oil P_c at S_{wi} provide limiting residual oil saturations under gravity drainage.

Slow Vertically Oriented Gasflood

An unsteady-state test was conducted on a six-inch long, vertically oriented core, at a very low injection rate of 0.5 cc/hour, corresponding to about 40 feet/year gas/oil contact vertical displacement. Saturation was monitored by the x-ray technique, and relative permeability was generated by measuring gas permeability at various saturation levels. The results are shown in Figure 7. The test produced a residual oil saturation somewhat higher than the pure gravity-dominated centrifuge data (or long core tests), but lower than that of the viscous dominated or steady-state tests, also shown in Figure 7. It is apparent that the lower rate of gas advancement results in improved displacement efficiency.

Figure 8 shows typical gravity-dominated gas-oil relative permeability curves. Oil relative permeability is obtained by high-speed centrifuge tests, and was validated using long core experiments. The gas relative permeability is obtained from a combination of unsteady-state, steady-state, long core, and interrupted centrifuge measurements.

Comparison of Measurement Techniques for the Characterization of Gravity Drainage

A wide range of different types of tests was used to characterize the gravity drainage process. A summary of the advantages and disadvantages of the various tests is shown in Figure 9.

Validation of S_{org} by Coring

Laboratory findings were validated by a subsequent coring operation, using a water based mud and low invasion techniques, in the secondary gas cap of the Ubit field which had been in production for twenty-five years. The oil saturations determined on the cored interval are shown in Figure 10. Oil was effectively absent from the region occupied by the primary gas cap. The residual oil saturation in the secondary gas cap was 2 to 6 %, when corrected for the oil formation volume factor. The low residual oil saturations found in the coring program are consistent with the lab experimental measurements. The oil saturation at the gas-oil contact increased rapidly with depth, in agreement with measured gas-oil capillary pressure data.

Validation of S_{org} by Reservoir Simulation

The new relative permeability curves were applied in a reservoir management study of the Ubit field. Ubit is characterized by generally excellent permeabilities (1 – 3 darcies) with no pressure-isolated blocks. The pressure difference across the entire reservoir has been less than 50 psi during the entire production history, and is anticipated to decrease to less than 20 psi as the remainder of the field is developed. The gas reservoir volume is approximately equal to that of the oil. Due to the large area, the gas velocity is low (2-3 feet/year), so the displacement is gravity stable. However, due to the high vertical permeabilities, wells are susceptible to coning which would be locally viscous-dominated flow. Water movement is slight except when coning occurs. The simulation grid consists of 93 x-direction cells, 40 y-direction, and 18 layers for a total of approximately 67,000 cells. 14 of the 18 layers reside exclusively in the oil zone for the purpose of capturing the oil displacement by gas. The PVT properties are treated in black oil mode. Relative permeability curves are taken from laboratory measurements for each of the seven facies types that have been identified in the reservoir.

The primary history match parameters are the pressure and the GOR. An approximate match of WOR has also been made, but since the field data, especially during the early years of production, is not accurate, and water movement is not important to field performance, most of the history-matching effort was focussed on the gas displacement. The application of the correct oil residuals and relative permeabilities, as described above for gravity-dominated flow, played a significant role in obtaining a match of the GOR data.

Another important history-matching parameter is the oil saturation behind the advancing gas front. When the simulation model was first constructed, only centrifuge relative permeability measurements without end-effect corrections were available. Even though the correct oil residual of 5-6% was used, the model calculated oil saturations from 8% to as much as 20% in the secondary gas cap after 25 years of production.

After applying the relative permeability curves from the coreflood simulator corrected for the end effects, the simulator-calculated oil saturations behind the gas front were close to the residual saturations. As pointed out above, these were the saturations which were actually observed in the field.

The corrected relative permeabilities led to a difference of 100 million barrels of oil production, or 10% of the total, in predicted ultimate recovery.

Modeling

Oil flow in gas-oil gravity drainage can be divided into three overlapping modes of transport: bulk flow, thread flow, and film flow. Bulk flow accounts for nearly all the oil permeability at high saturations. Above the percolation threshold gas saturation, flow in corners through oil "threads" becomes the dominant mode of oil transport. As oil saturation declines further, transport through stable oil films remains the only mechanism for continued oil flow, aside from diffusion and solubility considerations. Thread flow [5] and film flow [12] can be important mechanisms in producing low residual oil saturations, as often observed in gravity drainage processes. However, rates of oil flow can become extremely low. These low rates can be difficult to measure in the laboratory, which can easily result in underestimation of residual oil saturation [13]. For such processes, there exists a practical definition of residual oil expressed in terms of a lower limit in relative permeability. This limiting relative permeability need not be arbitrary; rather it can be defined relative to the life of a field process.

Another source of error in the characterization of a gravity drainage process arises in the interpretation of relative permeability from laboratory measurements in the low oil saturation range. Residual oil saturation may be properly identified, but the presence of capillary end effects can cause improper assignment between saturation and relative permeability. Several recent papers have dealt with the minimization of end effects in experiments [14,15]. An alternative is to make use of more advanced interpretation methods to history-match experiments with all known effects included in the analysis [9,10]. One approach would be to measure a capillary pressure curve in a companion test to every relative permeability experiment. Special core holders have been built to allow P_c and k_r measurement on the same core without removing the core sample [15]. With the known capillary pressure relationship, the relative permeability can be properly modeled. Others advocate simultaneous determination of k_r and P_c from single or multi-step experiments [16,17]. This requires use of a coreflood simulator in an inverse problem-solving manner and offers the advantage of producing internally consistent k_r and P_c which are reconcilable with simulation. The uniqueness of the match is still questionable and has been shown to be a function of what kind of data is collected, the accuracy of the data, and the experimental procedures [18].

Centrifuge experiments are often used in studies where gravity drainage is the identified as the dominant recovery mechanism. The ability to elevate the effective gravitational constant not only reduces experimental time, but allows more accurate estimation of the endpoint saturation. Premature termination of experiments is avoided due to the possible time compression. Still, depending upon the instrument parameters, rotational speed, and fluid properties, significant errors in relative permeability behavior can be introduced by failing to account for capillary effects in modeling transient centrifuge experiments.

At least two dimensionless groups can be examined to help portray the importance of capillary forces on the gravity drainage process, the Dombrowski-Brownell number [11], N_{DB}, and a macroscopic Bond number, N_B ,

$$N_{DB} = \frac{\Delta\rho\, g\, k}{\sigma} \qquad (1)$$

and

$$N_B = \frac{\Delta\rho\, g\, L}{P_c^*}\ , \qquad (2)$$

where, $\Delta\rho$ is the fluid density difference, g is the effective gravitational constant, k is the medium permeability, σ is the interfacial tension, L is the sample length, and P_c^* is a characteristic capillary pressure, taken as the critical entry pressure for gas. Both are ratios of gravitational-to-capillary forces but have different choices of characteristic length scale. N_{DB} can be interpreted as a microscopic version of the Bond number. Typical values for the macroscopic Bond number suggest that no correction is needed in residual oil saturation in order to scale between lab and field conditions. However, typical values of the microscopic Bond number, N_{DB}, suggest that capillary forces cannot be neglected on the scale of fluid flow. This is true primarily when saturation variation occurs in the sample, although this shows up nowhere in the definition of N_{DB}. In fact, N_{DB} can be used as an indicator when saturation variation is expected. When present, it must be accounted for in the interpretation of relative permeability, especially in the range of low saturation. We could modify the definition to reflect the dependence upon saturation by capturing the effective permeability, k_r.

$$\tilde{N}_{DB} = \frac{\Delta\rho\, g\, k k_r}{\sigma} \qquad (3)$$

As saturation decreases, the modified Dombrowski-Brownell number decreases -- increasing the effect of capillarity. In practice, Eqn. 3 is difficult to use, since relative permeability is often the parameter to be determined.

Results and Discussion

Long Core Experiment

A plot of oil production vs. time is shown in Figure 11. As is evident, more than half of the total produced oil was produced during the early free drainage stage. This means that the length of the core generated adequate head (10"/12" * 0.3 psi/ft) to exceed the gas-oil P_c entry pressure, the capillary pressure responsible for holding oil in place. Capillary desaturation using a porous plate was begun on the third day of the experiment. The first gas permeability was measured on day 12 of the experiment. The oil saturations shown on the plot were monitored using x-ray attenuation and verified using the final fluid saturations measured by Dean Stark. The fluid saturations measured by Dean Stark at experiment end, and the rock properties measured subsequently are shown in Table 4. The core drained almost uniformly, top-to-bottom. A very uniform residual oil saturation was attained in all segments of the core, with a composite value of 10.1%.

Figure 12 shows x-ray scan data along the length of the core at selected times in the experiment. It shows that, as expected, the oil drains first from the top of the core. It shows that by the end of the experiment, under 4 psi capillary pressure, the fluid saturation along the length of the core was nearly uniform.

Figure 13 shows microwave scan data at selected points along the length of the core. It shows that there was an increase (about 6%) in water saturation at the bottom of the core as the experiment progressed. This increase was confirmed by the Dean Stark water determinations. This migration of water may indicate that the initial water saturations were somewhat above 'immobile' water content in a gas-oil displacement.

The relative permeability to gas is shown in Figure 8. Note that the relative permeability to oil shown in this figure does not come from a long core experiment, but was made using a centrifuge method. The gas and oil relative permeability curves for one section of the core used in the long core experiment are shown in Figure 8.

Comparison of Gasflood and Gravity Drainage Processes

Figure 7 shows that the relative permeability to oil in a gravity drainage process is higher than in a gasflood. But, most importantly again, the residual oil saturations from the conventional gasflood tests were much higher than from the gravity drainage tests.

S_{org}, k_{rog} and Rock Properties

The much reduced residual oil saturation in gravity drainage is due to the inherent stability of the displacement front and the ability of oil to maintain connectivity through thin films throughout much of the process life. These features of gravity drainage make S_{org} roughly independent, for high quality rocks, of the water saturation and the sample permeability. Permeability is controlled by pore throat and pore size distribution, whereas film drainage should be affected more by fluid-fluid surface area and pore topology. In displacement experiments, phase trapping is controlled by interfacial instabilities at pore throats and pore junctions. Conversely, gravity drainage S_{org} is influenced strongly by the stability of films on pore walls or separating gas and water phases. The gravity drainage residual oil saturations from Ubit and several similar reservoirs are replotted against the initial water saturation in Figure 14, showing no distinct trend between S_{wi} and S_{org}. Figure 15 shows that the residual oil saturation to gravity drainage is not strongly dependent on reservoir facies. Residual oil saturations to gravity drainage in channel facies (average S_{org}=6.6%) and shoreface facies (average S_{org}=6.5%) were statistically indistinguishable. Samples from poorer quality reservoir rocks showed somewhat higher residual oil saturations (lower shoreface - shelf facies average S_{org}=9.4%). Overall, in high quality sands, no residual oil saturation greater than 13% was measured.

Relative permeability in a gravity drainage process, unlike S_{org}, does depend strongly on rock quality. Figure 16 illustrates the variation observed in oil relative permeability measurement for samples with a wide range in air permeability. The S_{wi} in these samples was established at high capillary pressure by either porous plate or centrifuge methods. The S_{wi} values correlate with rock permeability. These curves collapse into a single curve when normalized for initial water saturation.

Conclusions

Residual oil saturation to the gravity drainage process (S_{org}) is low, 3-10% with an average of about 7% in very high permeable channel and shoreface facies sands, and 9% in lower shoreface-shelf facies. <u>This level of saturation is achieved through film drainage and may require considerable time and suitable conditions (oil column height, fluid density differences, non-oil-wet conditions).</u>

Multiple tests may be needed to characterize the gravity drainage process.
Long core gravity drainage, capillary desaturation, and centrifuge displacement studies were performed to establish this range in S_{org}. Gas-oil centrifuge tests are by far the quickest, since the gravitational force can be elevated to allow gravity-dominated oil production measurements and k_{ro} estimation, even at very low oil saturations. Gas-oil capillary pressure tests, done by porous plate or centrifuge, give access to limiting endpoint saturation information as a function of height above the gas-oil contact. The long core experiments, as performed, yielded gas relative permeability measurements during gravity drainage and gave upper bound estimates of S_{org}. The practical residual oil saturations from the long core experiments were reported with respect to the production rate when the experiments were terminated. Our long core gravity drainage tests validated our findings with more easily performed measurement techniques.

Conventional gas flood tests give higher S_{org} (average 30%), even at high volume (1000 PV) and/or low rate gas injection. They do not represent the gravity drainage process.
We discovered that even low rate gas injection (0.5 cc/hr) in a vertical core orientation did not give residual oil saturations characteristic of gravity drainage. In-house measurements on a large number of cores substantiated the literature claims that gas flooding and gravity drainage are distinct processes with substantial difference in process efficiency. While gravity drainage is a slow process, gas flooding traps significantly more oil.

S_{org} may depend on fluid properties.
We did not perform sensitivity studies on the effect of fluid properties on gravity drainage residual oil saturations, but the residual oil saturations obtained using mineral oil, or oils from several other reservoirs in the region, were not different from those obtained using Ubit crude oil. However, the literature suggests that the ability for oil to spread at the gas-water interface is a critical parameter in determining endpoint saturation. Our tests on long cores sometimes were performed with crude oil diluted with a suitable solvent to yield reservoir condition viscosity. Performing displacements with crude oil was essential to obtain credible gravity drainage results. Since the density contrast also controls the balance between gravity forces and capillary retention, fluid density is a controlling parameter in gravity drainage. Additionally, some centrifuge gravity drainage tests on similar samples were performed using mineral oil. The results of these tests were not statistically different from those tests conducted using reservoir crude oil.

S_{org} does not depend strongly on rock properties
Although rock structure impacts production rates, and hence relative permeability, it seemingly does not dictate the ultimate recovery by gravity drainage in the class of unconsolidated sands under investigation (channel and shoreface facies). Tests conducted on Ubit channel and shoreface sands with permeabilities ranging from 1650 to 4400 md and porosities from 24.9 to 35.6% did not show a dependency of S_{org} on porosity or permeability. However, measurements on unconsolidated, poorer quality (lower shoreface-shelf) sandstones do show slightly higher residual oil saturations to gravity drainage.

S_{org} does not depend strongly on initial water saturation within a reasonable range (at and somewhat above the reservoir S_{wi}).
Lab tests on different samples do not show sensitivity between S_{org} from gravity drainage tests and S_{wi}, at least in the low to moderate water saturation range. This is consistent with literature findings. However, lab tests should be run with a reasonable S_{wi}. Tests run in the absence of a connate water film do show higher residual oil saturations [12,13].

k_{ro} depends on rock properties.
The rate of free-fall gravity drainage is dictated by medium permeability, as gas replaces oil. In later stages of gravity drainage, oil continues to drain through films. The oil relative permeability at low oil saturations is then expected to be a strong function of the rock fabric. It seems that the dependency is correlated with rock permeability.

k_{rg} depends on rock properties

Gas permeability at high oil saturations in gravity drainage is constrained by the oil mobility, as gas is replacing the oil that moves under the influence of gravity. We have observed that the endpoint gas permeability correlates with rock permeability.

Nomenclature

g	effective gravitational constant
GOR	gas-oil ratio
k	permeability
k_r	relative permeability
k_{rg}	relative permeability of gas
k_{ro}	relative permeability of oil
L	sample length
N_{DB}	Dombrowski-Brownell Number
N_B	Bond Number
OOIP	Original oil in place
P_c	capillary pressure
P_c^*	characteristic capillary pressure
PV	pore volume
S_{wi}	initial water saturation
S_{org}	residual oil saturation to gas displacement
STOIIP	stock tank oil initially in place
WOR	water-oil ratio

Greek Symbols

σ	interfacial tension
$\Delta\rho$	density difference

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Table 1
Ubit Field Gravity Drainage Experimental Results

Well	Sample Depth (ft.)	Facies	Air Permeability (md), (NOB)	Porosity(%) (NOB)	Test (Conditions)	Initial Water Satn. (%)	Residual Oil Saturation Sorg (%)
Ubit 35G	6290.5	Channel	3459	26.5	Pc (1)	7.1	11.6
Ubit 22D	5950.9	Shoreface	4392	30.7	Pc (1)	2.67	10.1
Ubit 35G	6290.5	Channel	3459	26.5	kr (2)	7.1	9.1
Ubit 22D	5950.9	Shoreface	4392	30.7	kr (2)	6.1	10.1
Ubit 60I	5529.4	U. Shoreface	2258	32.0	kr (3)	3.1	4.0
Ubit 60I	5552.9	U. Shoreface	3738	35.6	kr (3)	3.1	9.0
Ubit 60I	5588.5	L. Shoreface	2075	31.5	kr (3)	4.1	4.0
Ubit 60I	5603.6		2945	34.9	kr (3)	15.1	5.9
Ubit 60I	5685.4	LS-Shelf	345	27.7	kr (3)	36.2	6.3
Ubit 28M	5832.0	Channel	1650	24.9	Pc (4)	0.8	4.6
Ubit 35G	6297.0	Channel	3020	27.9	Pc (6)	16.7	5.4
Ubit 35G	6297.0	Channel	3020	27.9	kr (8)	16.7	7.5
Ubit 22D	5948.8	Shoreface	3880	31.1	Pc (7)	6.8	3.6
Ubit 22D	5950.2	Shoreface	3520	31.0	kr (8)	8.6	8.5
Ubit 22D	5950.2	Shoreface	3520	31.0	Pc (6)	8.6	2.2
Ubit 35G	6297.2	Channel	2490	28.7	kr (5)	9.2	19.0*
Ubit 22D		Shoreface	2530	28.4	G.D. (9)	10.8	12.3#
Ubit 22D	5814	Shoreface	3447	33.1	G.D. (9)	17.7	10.1#
						Average	**6.7**

(NOB) Net overburden. Porosities and permeabilities were measured under reservoir net confining stress.
* Gasflood data; not included in average
# Terminated before endpoint saturation reached; not included in average

Test Conditions Key

(1) Gas-oil Pc, centrifuge 150 F, 2600 psi, reservoir fluids
(2) Gas-oil kr, centrifuge 150 F, ambient P, res. fluids
(3) Gas-oil kr, centrifuge, ambient T & P, res. fluids
(4) Gas-oil Pc, porous plate, 180 F, 3500 psi, res. fluids
(5) Gas-oil kr (using USS gasflood), followed by porous plate 180 F, 2800 psi, doped res. fluids
(6) Gas-oil Pc, centrifuge, 160 F, 2800 psi, res. fluids
(7) Gas-oil kr, unsteady state porous plate, 180 F, 2800 psi, doped res. fluids
(8) Gas-oil kr, centrifuge, 160 F, 2800 psi, res. fluids

Table 2
Results of Published Gravity Drainage Experiments on Sandstones

PUBLICATION	AUTHORS	DATE	PERMEABILITY (md)	POROSITY (%)	WATER SATN. (%)	RESIDUAL OIL SATURATION Sorg(%)
1) Improved oil and gas recovery using nitrogen lab analysis.	J. P. Clancy R. E. Gilchrist	1985	95	19.0	19.0	2.0
2) Prediction of oil recovery by gravity drainage	H. Dykstra	1978	227	22.9	19.0	1.0
3) Engineering study of Hawkins Woodbine reservoir	R. L. King	1995	1194	26.5	25.0	1.0
			3396	27.9	9.6	
4) Gas flooding experiment with Long Core	J. A. Stensen	3/90	260	27.1	22.6	13.1
5) Gravity Drainage Project	N. C. Sargent	3/93	1910	18.0	18.0	10.0
			1910	18.5	18.0	8.0
6) Oserberg long core sweeping of reservoir oil by gas cap	P. Chaulet G. Rigaudie	1982-83	570	24.6	32.6	0.5
7) Oil recovery by gravity drainage during gas injection	H. Skvrdal O. Hustad, T. Holt	5/96	2720	23.6	34.1	4.7
			2310	23.5	35.2	6.7
		(Spreading)	2450	23.3	35.5	12.6
		(Non-spreading)	2320	22.4	30.1	6.7
			2530	21.9	31.6	8.2
			2320	22.8	25.4	1.1
8) Gravity drainage during gas injection	P. Naylor N. C. Sargent, et al.	5/95	1470	18.5	18.0	10.0
			2000	18.7	2.0	13.0
9) Sweeping or reservoir oil by gas cap	P. Chaulet G. Rigaude	3/84	1100	24.6	25.2	5.5
10) Drainage PC functions and influence of connate water	J. M. Dumore' R. S. Schols	10/74	1620	23.2	14.3	3.0
11) Possibilities of secondary recovery for the OKC Wilcox	D. L. Katz	10/41	410	14.6	15.0	7.2
			628	15.6	15.0	8.0
12) An engineering study of Hawkins Woodbine reservoir	R. L. King W. J. Lee	9/75	3396	27.9	9.6	3.5
			-----------	----------	----------	----------
		AVERAGE	**1659**	**22.1**	**21.7**	**6.3**

Table 3
Parameters Used in Monitoring MEPTEC Long Core Experiments

X-ray System Parameters	
X-ray System	Philips Model MCG40
Detector	Scintillation
Power	50 kv, 40 ma
	80 kv, 0.5 ma
Scan Frequency	1 hour
Scan Step Size	1.0 cm.
Microwave System Parameters	
Analyzer	Hewlett Packard 8720C
Antenna	Small horn, non-focusing
Scan Frequency	1 hour
Scan Step Size	1.0 cm.
Other Measurement Parameters	
System Pressure Frequency	6 min.
Produced Oil Weight Frequency	6 min.

Table 4
Properties and Fluid Saturations of Ubit Core Long Core Gravity Drainage Experiment

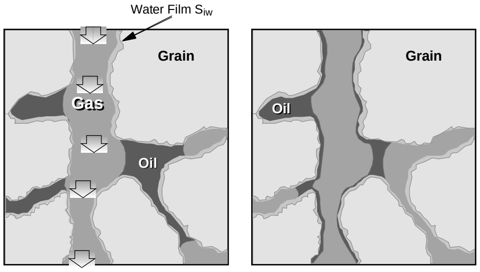
	TOP			BOTTOM	
Sample Number	A	B	C	D	Composite
Water Saturation, %	15.3	15.8	16.5	22.3	17.7
Oil Saturation, %	10.7	9.1	10.6	9.9	10.1
Pore Volume, cc	28.2	38.5	53.2	43.7	163.6
Length, cm	4.43	5.86	8.05	6.66	25.00
Diameter, cm	5.09	5.00	5.00	5.01	
Porosity, %	31.3	33.4	33.7	33.3	33.1
Permeability, md	2320	3320	4040	4200	3447

Brine Density	1.006 @ 76 °F, g/cc
Oil Density	0.824@ 76 °F, g/cc
Net confining stress	2000 psi
Test Temperature	170°F

Volume Correction Factors:

Brine	1.025
Oil	1.043

Gasflood vs. Gravity Drainage



GASFLOOD:
Residual Oil Disconnected

GRAVITY DRAINAGE:
Residual Oil Connected by Thin Films

Modified from Huang & Hoefner, 1994

Figure 1

Residual Oil Saturation Gasflood Tests Do Not Represent the Gravity Drainage Process

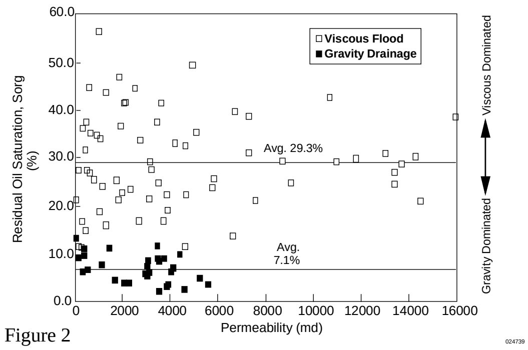


Figure 2

Mobil Vertical System for Gravity Drainage Measurements

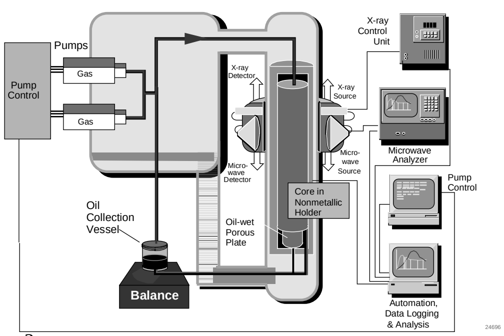


Figure 3

X-ray Calibration Endpoint Scans

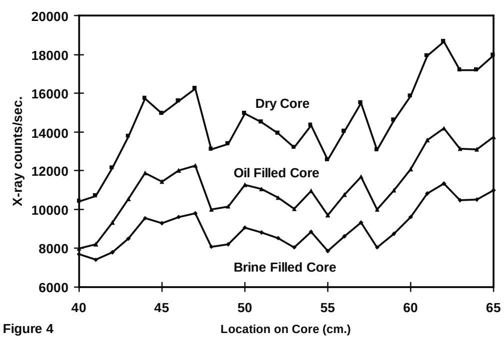


Figure 4

Microwave Calibration Endpoint Scans

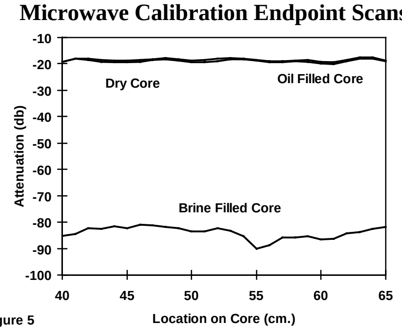


Figure 5

Typical Gas-Oil and Water-Oil Pc Curves

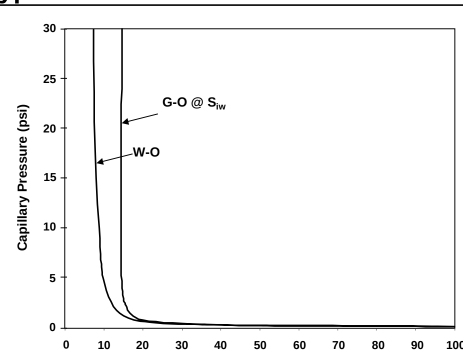


Figure 6

Comparison of Kr from Gasflood and Centrifuge Tests

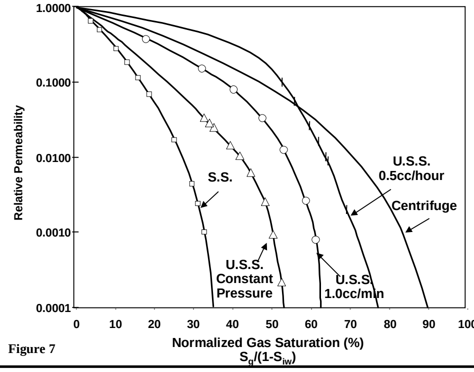


Figure 7

Typical Gas and Oil Relative Permeabilities for High Quality Rocks

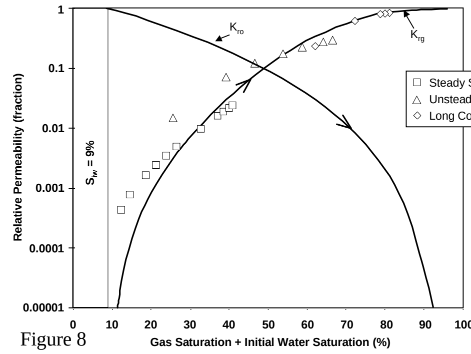


Figure 8

Evaluation of Tests for Characterizing Gravity Drainage Process

	Long Core Experiment	Centrifuge	Conventional Steady & Unsteady state	Modified Steady & Unsteady state
Pc Strength	Reliable Pc; Simulated ResCon.	Reliable Pc at high rpm; Fast	Fast	Measured Pc
Pc Weakness	Slow	Unreliable at low rpm; Dead oil.	Pc to be modeled.	Slow
Kr Strength	Reliable Sorg, Krg; End effects can be minimized.	Pc may be neglected at high rpm; Fast	Reliable Krg Simulated ResCon. Fast	Combined Kr, Pc Simulated ResCon. Krg, Kro
Kr Weakness	Modeled Kro; Pc must be used in Kro model; Slow	Pc must be used in Kro model; Dead oil	Kro not for gravity dominated systems	Kro not for gravity dominated systems

Figure 9

Oil Saturation in Gas Cap, Secondary Gas Cap, and Oil Zone

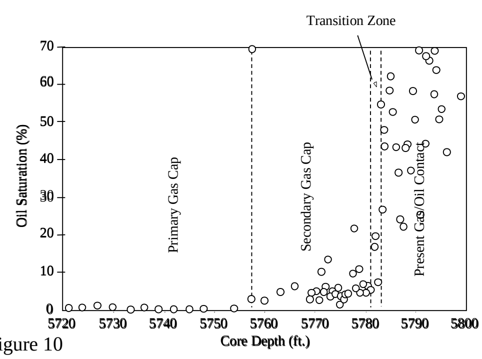


Figure 10

Gravity Drainage Experiment Gas-Oil Relative Permeability vs. Oil Saturation Measurements

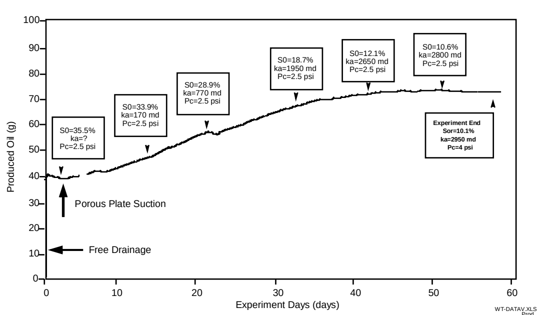


Figure 11

Oil Saturation During Gravity Drainage Experiment Using X-ray Scans

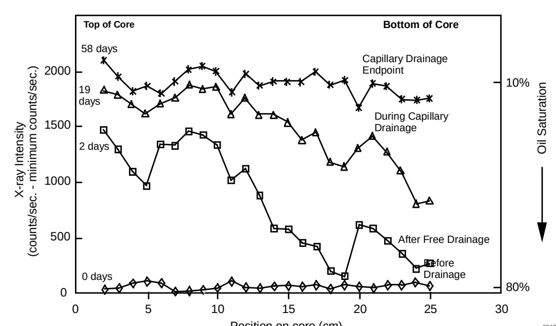


Figure 12

Microwave Signal at Three Selected Points Along the Core Shows Variation with Time in Brine Saturation

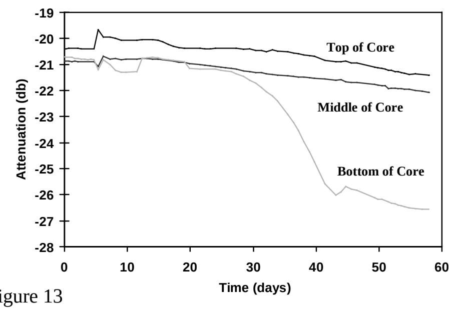


Figure 13

Residual Oil to Gravity Drainage Shows No Clear Relationship Between Swi and Sorg

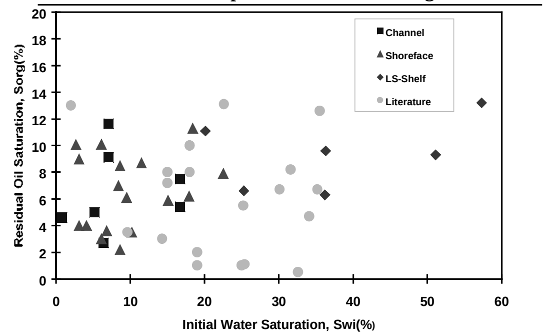


Figure 14

Residual Oil Saturation to Gravity Drainage Is Not Strongly Dependent on Rock Properties

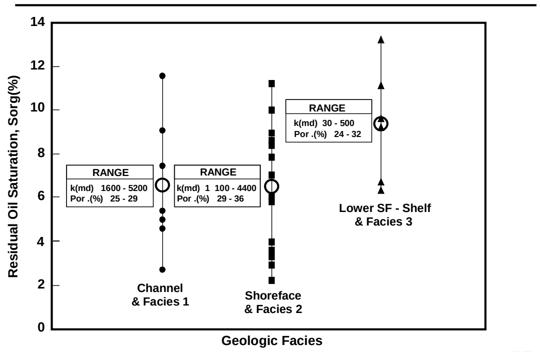


Figure 15

Oil Relative Permeability

Gravity Drainage Process

Sample Permeability from 25 to 5000 md.

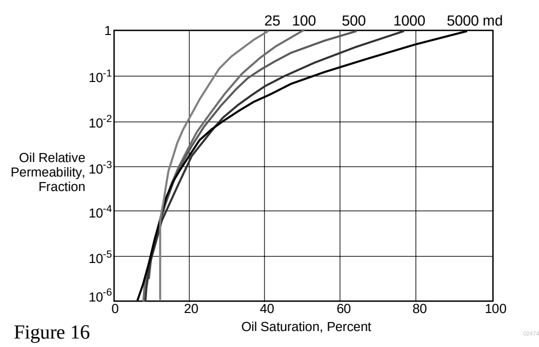


Figure 16