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RESERVOIR ENGINEERING RESEARCH INSTITUTE

PROJECT 5 - SOLUTION-GAS DRIVE IN LIGHT AND HEAVY OIL RESERVOIRS

Visualization and Measurement of Gas Evolution and Flow of Light and Heavy Oil in Porous Media

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VISUALIZATION AND MEASUREMENT OF GAS EVOLUTION AND FLOW OF HEAVY AND LIGHT OIL IN POROUS MEDIA

SUMMARY

In a number of experiments, the efficiency of solution-gas drive for both a light and a heavy oil was studied. These experiments reveal that solution-gas drive for a heavy oil of 11 API gravity is more efficient than a light oil of 35 API gravity.

INTRODUCTION

Solution-gas drive is one of the basic recovery mechanisms. Two parameters that affect the efficiency of this process are: 1) critical gas saturation, and 2) mobility of the gas phase. From the recovery standpoint, high critical gas saturation and low gas mobility both contribute to high recovery efficiency; low critical gas saturation and low gas mobility could also result in high recovery. From the fundamental viewpoint, solution-gas drive is the bubble-nucleation process, where, at some critical supersaturation pressure below the bubblepoint pressure, the formation of gas bubbles occurs, and then these bubbles grow. Recently, based on theoretical analysis,[1] we have demonstrated that bubble nucleation in porous media is an instantaneous nucleation process; all bubbles form instantaneously at the critical supersaturation pressure. Once bubbles are formed, they grow. The efficiency of the solution-gas drive process is expected to be related to the number of gas bubbles and their growth. The bubble density (i.e., number of bubbles per unit volume) and their growth affect the critical gas saturation and the gas mobility. The number of gas bubbles may depend on: 1) reservoir crude, 2) porous media, and 3) rate of pressure decline. These effects are not currently understood.

It is known that a number of heavy oil reservoirs in Canada (viscosity in the range of 200 to over 20,000 cp) have a high recovery efficiency -- around 15 to 20 percent by primary depletion.[2,3,4] The high recovery is achieved in the absence of gravity drainage and water drive. Solution-gas drive is believed to be the only mechanism contributing to

such a high recovery rate in heavy oil reservoirs. From common reservoir engineering knowledge based on compressibility, recovery is estimated to be some 2 to 4 percent.

The Celtic field in Canada has produced oil under both primary recovery and cyclic steam injection.[3] The saturated oil has a viscosity of 2000 cp. The initial solution gas-oil ratio was 10 volume/volume, and the inital reservoir pressure was about 480 psia. Recovery factor to 1992 was as high as 14 percent. Although thermal recovery has been experimented with in this field, the unusually high primary production from solution-gas drive was considered to be the key commercial exploitation. Reference 3 reports that in some of the heavy oil reservoirs in Canada, several wells which were prolific producers by primary production showed very poor response to steam stimulation. The field performance of these heavy oil reservoirs, leads us to believe that the type of oil may be an important element of solution-gas drive process. Therefore, the second objective of this work is to study the effect of the type of oil on gas bubble formation and growth.

Our previous experimental work revealed very low critical gas saturations -- values in the range of 0.5 to 2 percent.[5] Model C_1/nC_{10} fluids were used in the measurements. Literature values are higher than our data.[5,6] Some authors suggest that boundary effects may be the cause of ambiguity in critical gas saturation.[7] Another objective of this work is to clarify ambiguities regarding critical gas saturation.

The main goal of this study is to determine the efficiency of solution-gas drive for both heavy and light oils. In the following, we will first describe a special visual coreholder, which was designed to visually observe the appearance and growth of gas bubbles and gas flow. The results of the experiments will then be presented, and at the end conclusions will be drawn from the work.

EXPERIMENTAL

A schematic of the experimental apparatus is shown in Figure 1. The setup, with slight differences, was used for the three sets of experiments. The main components of the apparatus include the visual coreholder, a high pressure chromatography pump,

pressure transducers, a system for providing a constant temperature of 77° F (±0.3° F), and a video recording system.

The specially-designed visual coreholder consists of an 8" long x 2" diameter Berea sandstone core (pore volume ≈ 95 cm^3, permeability ≈ 500 md), capped at either end with a plexiglass cap (the top cap machined with a dead-end for trapping gas evolved from the core) and sealed with a heat-shrunk teflon sleeve. Surrounding the core is a water-filled translucent chamber, which is pressurized and acts as an overburden sleeve. Plumbed to the coreholder is a constant flow/pressure pump. The pump is used both for saturating the core system and for pressure decline, through volume expansion. The pressure transducers are used for mapping the pressure response behavior of the system throughout the expansion experiments. A video system is used for visually monitoring the experiment. In addition, a 35 mm camera is used for some still photographs of the system.

In a typical experiment, after assembling the coreholder in the vertical position and pressurizing the overburden sleeve to about 800 psia, the Berea core was exposed to methane at a pressure of approximately 500 psia to achieve adsorption on the rock surface. The methane was then displaced by the test fluid at test pressure, and an extra 1.2 pore volumes of fluid was passed through the core system to ensure that the core was saturated with the test fluid of the correct composition. The saturation period varied widely for the different fluids used, from less than one day to over two months for the heavy oil.

The experiments consisted of starting with the core system saturated with the test fluid at a pressure above the bubblepoint pressure, usually in the neighborhood of 650 psia. Then the pump was placed in the constant volume expansion mode. A computer interface system was used to log the pressure measured at either end of the core with transducers. In the next section, the resulting pressure versus volume expansion plots are presented for the various fluid systems and for different expansion rates. In addition, photographs of the core surface at various expansions for two of the experiments are presented to show the bubble evolution behavior observed.

RESULTS

Model Light Oil

A mixture of C_1/C_3 -- 15.125 mole % C_1 and 84.875 mole % C_3 -- was used in the following two tests. The calculated bubblepoint pressure of the mixture at 77° F is 478 psia (with the Peng-Robinson equation of state[8]). The surface tension and the viscosity at the bubblepoint are 4.5 dyne/cm,[9] and 0.08 cp,[10] respectively.

Test 1: 0.3 cm^3/hr Expansion Rate -- In this test, the C_1/C_3 mixture at an initial pressure of 650 psia was expanded at a rate of 0.3 cm^3/hr. The expansion was carried out by fluid extraction from the bottom. At the top of the core, an open space of 10 cm^3 was provided to be filled by the gas from the core. About 4 cm^3 of this space (the cap) could be viewed.

Fig. 2 shows pressure-volume expansion data for this test. As the figure shows, in the single phase liquid state the pressure declines rapidly to an expanded volume of 1.25 cm^3 (to 472 psia). Then the pressure rises slowly, indicating the evolution of the gas phase. After the volume has expanded to 2.8 cm^3, the pressure decreases with a slope of about -1.6 psi/cm^3.

A total of nine small patches of gas were observed to form simultaneously on the front half of the vertical rock face at the volume expansion of 1.5 cm^3. These patches were evenly distributed across the core. During the expansion from 1.52 to 2.57 cm^3, the patches of gas increased in size, connected and formed bigger patches until they were all connected at 2.57 cm^3 expansion.

At the volume expansion of 2.59 cm^3, a filament of gas bubbles was observed flowing out of the top face of the core into the open space of the top cap (photograph of the top cap will be shown later). From 2.59 to 2.74 cm^3 expansion, 13 bursts of gas filaments were observed flowing out of the core. The duration of the bursts varied from

0.7 to 0.93 seconds. One hour after the first string of the gas filament was observed (at 2.89 cm^3 volume expansion), the time interval between bursts of gas bubbles was about 1.5 minutes. For the remainder of the test, there were approximately 40 to 45 bursts of bubbles per hour. The duration of each burst of gas bubbles varied from 0.7 to 1.3 seconds, but for most bursts the duration was 0.77 to 1 second. All the bursts came from a single location on the core surface outlet. At a volume expansion of 8.9 cm^3, the gas had filled a dead space of about 6 cm^3 in the open space outside the core. The gas saturation in the core is estimated to be around 1.8 percent at this volume expansion. The expansion was continued to 14 cm^3. At this time, the gas nearly filled the open space at the top of the core (i.e., 10 cm^3 of gas). The amount of the gas in the pump was also measured by pressurizing the fluids in the piston, and the gas in the core was estimated to be around 2 percent.

For this test, based on the observation of the first continuous gas flow from the top face of the core (at volume expansion of 2.59 cm^3), the critical gas saturation is estimated to be around 1 percent of PV. The displacement efficiency at the end of the test at 14 cm^3 expansion is, however, around 2 percent. We measured a pressure increase of 2.5 psia at the termination of the test, which indicates a supersaturation of 2.5 psia. The pressure increase occured in a period of 5 hours.

Test 2: 0.06 cm^3/hr Expansion Rate - In the second test, the expansion rate was five times less than in the first test. But, similar to Test 1, the withdrawal was from the bottom face of the core. The fluid mixture in the core was initially at 650 psia and expansion into the pump started from this pressure. Fig. 2 shows the pressure vs. volume expansion from a pressure of around 595 psia. The same figure also shows the pressure-expansion data of Test 1. Prior to gas evolution, Tests 1 and 2 have nearly identical expansion behavior. Around an expansion volume of 1.2 cm^3, the slope of the pressure-expansion volume plot changes. The pressure has a slight increasing trend from an expansion of 1.2 to 2.8 cm^3. Thereafter, it reduces linearly with a slope of about -1.1 psi/cm^3. The critical supersaturation pressure (the pressure at which gas evolves from the

supersaturated liquid) is around 475 psia, which is slightly higher than the critical supersaturation pressure for Test 1. The maximum supersaturation for this test is, therefore, around 3 psi.

Visual observation of the core surface revealed gas forming first at one spot 2 cm from the bottom face of the core at 1.36 cm^3 volume expansion. The surface area of this first gas patch increased to 15 mm^2 at volume expansion of 1.4 cm^3. The gas patch grew in a path upwards around the core and its width increased with time. Around 1.42 cm^3 expansion, another patch of gas appeared about 5 cm from the bottom face of the core. The first patch continued to "snake" around the core and at 1.5 cm^3 expansion, it had a distance of about 8 cm from the top face of the core and 1 cm from the bottom face. It is likely that only one gas bubble was formed initially in this test. The second patch could be due to the growth of the bubble inside the core.

The flow of the gas from the core was first observed at 1.84 cm^3 expansion. During the first hour (from 1.84 to 1.90 cm^3), four bursts of gas bubbles were observed. The duration of the gas bubble burst lasted from 0.8 to 1.2 seconds. For the remainder of the test, there were about 9 bursts of gas bubbles per hour. The duration of each burst of gas bubbles varied form 0.73 to 1.03 seconds, but mostly from 0.83 to 1.0 seconds. Similar to Test 1, all the gas bubbles flowed from the same point of the core top face. At the termination of this test, we continued to measure the pressure. There was no pressure increase, indicating negligible supersaturation.

Based on the observation of the first flow of gas, the critical gas saturation for Test 2 is estimated to be around 0.5 percent. The displacement efficiency of solution-gas drive seems to be very low for this test -- around 1 percent of PV at the end. A very high gas mobility precludes high recovery efficiency.

Heavy Oil

A heavy oil with a bubblepoint pressure of 445 psia at a temperature of 76° F was used for the two tests described in the following. It was prepared by mixing a stock tank

oil of 11 API gravity and methane with a ratio of 10 cm^3 of methane to 1 cm^3 of stock tank oil at standard conditions of 14.69 pressure and 60° F. The viscosity of the saturated oil at 57° F was 17,000 cp. The compressibility of the live oil above the bubblepoint pressure was 1.8×10^{-5} $psia^{-1}$. The compressibility of the total rock fluid system in the single phase state at 76° F was 2.5×10^{-5} $psia^{-1}$.

The saturation of the core with the heavy oil was a real challenge. It took more than two months to saturate the core.

Test 3: 0.06 cm^3/hr Expansion Rate -- In the first test on heavy oil, the expansion was carried out from an initial pressure of 645 psia. The production was from the bottom end of the core. On the top, the volume of the cap (open space) was about 4 cm^3. This whole volume could be viewed.

Fig. 3 shows the measured pressure-volume expansion data. The two data sets correspond to the output of the two pressure transducers. The upper curve, open squares, shows the pressure on the closed side of the system, and the lower curve is the reading of the transducer located on the expansion side of the core. In the early stage of expansion, the pressure declines rapidly, as expected. Both upper and lower pressures continue to decrease to pressures of 405 and 385 psia at a volume expansion of 1 cm^3. At this point, both curves flatten out, indicating the evolution of the gas phase. The supersaturations at expansion of 1 cm^3 are 40 and 60 psi for the top and bottom sides. Note that there is a substantial difference between the upper and lower pressures. The high pressure drop could be partly due to a narrow outlet at the bottom face of the core (diameter = 3mm).

At an expansion of 1.45 cm^3, some gas bubbles were visible on the outer surface of the core. We did not monitor gas bubbles on the surface of the core from 1 to 1.45 cm^3 volume expansion, therefore, gas bubbles might have appeared prior to volume expansion of 1.45 cm^3. The bubbles were mainly located in the bottom 5 cm of the core, but several bubbles were observed as high as 15 cm from the bottom. There were

approximately 50 to 60 small bubbles visible on the surface of the core. Further expansion to 1.7 cm^3 yielded a slight increase in the number and size of the existing bubbles. At this expansion a gas pocket was observed in the transparent tube in the lower end cap of the core (photographs to be shown later). The approximate volume of the gas slug was 0.04 cm^3. An interesting pressure fluctuation occured at an expansion of 2.67 cm^3. At this volume expansion the lower (expansion) pressure increased while the upper pressure decreased. The pressure change continued for one hour (0.06 cm^3), at which time the lower pressure increased by 10 psi and the upper pressure dropped by 5 psi. The trend then reversed itself and the pressures returned to their previous levels and decline rates. This behavior was witnessed repeatedly at later times, where it was observed to coincide with the production of gas pockets from the core into the transparent outlet tube. At an expansion of 2.91 cm^3, two gas slugs were observed in the core outlet tube. The upper slug was 3 mm in length, 18 mm below the bottom surface of the core. Below this slug was 5 mm of oil and then another gas bubble 2 mm in length. Based on a tube diameter of 3 mm, the volume from the bottom bubble to the bottom of the core is 0.22 cm^3, which corresponds well with the volume expansion of 0.24 cm^3 (4 hours) from the time of the pressure fluctuation to the visual observation. At the volume expansion of 2.91 cm^3, the core surfaces showed an increase in the number of gas bubbles towards the upper parts of the core. But, no bubbles were observed in the uppermost 2 cm of the core surface. Several more pressure spikes occured at volume expansions of 3.52, 4.20, 4.56 and 6.03 cm^3 (see Fig. 3). From volume expansion of about 7.4 cm^3, the fluctuations occured much more often. This is displayed by the jagged appearance of the pressure volume curve from this point to the termination of the experiment at an expansion of 11.88 cm^3. At the termination, the volume of gas in the pump was measured to be 1.3 cm^3 by compressing the fluids in the pump. This means that about 10.6 cm^3 of oil was produced from the core. Subtracting the contribution from fluid expansion, and since the formation volume factor is very close to unity, the oil recovery due to solution-gas drive is about 10 percent.

While at an expansion of 1.7 cm^3, gas was observed in the outlet tube; it may well have evolved from the oil outside the core, being that the lowest pressure in the system was near the expansion pump. A more logical choice for a gas flow might be at an expansion of 2.67 cm^3 where, as discussed above, gas slugs were produced from the core. Due to the uncertainty in gas flow, critical gas saturation could not be established for this test.

The main finding from this test is the very high recovery of about 10 percent heavy oil from the solution-gas drive process to a pressure of some 320 psia. This new and important finding confirms that solution-gas drive can be a very important recovery process for some heavy oil reservoirs.

Test 4: 0.06 cm^3/hr Expansion Rate -- In this test, the direction of flow was reversed with the expansion pump connnected to the top of the coreholder, rather than the bottom. This change was made in order to measure the flow of the gas from the core in the cap at the top.

Fig. 4 shows the measured pressure-volume expansion data. The two curves correspond to the pressures on the closed side (bottom) and the expansion side (top) of the core. During the initial stage of expansion in the single phase liquid state, the pressures on both sides of the core were a few psi different. Both pressures continued to decrease to 404 and 395 psia at expansion of 0.86 cm^3. This point corresponds to a local minimum for both pressures, indicating evolution of the gas phase. The critical supersaturation is, therefore, 40 to 50 psi. The data plotted in Fig. 4 are from manual readings and do not include data points where pressure fluctuations similar to Fig. 3 are observed. But, as Fig. 4 shows, the difference between the two pressures increases with volume expansion.

At expansion of about 1 cm^3, many small gas bubbles (approximately 100 to 150) were visible on the outer surface of the core. These bubbles were mainly located in the top three-fourths of the core. The appearance of gas on the core surface is displayed in Fig. 5 for varying amounts of volume expansion. The pictures in this figure were taken at

1.28, 2.32, 5.30 and 12.90 cm^3 expansions. Fig. 5a corresponds to about 5 hours after the appearance of the gas bubbles. There was very little change in the number of bubbles from the time of their formation to the expansion of 1.28 cm^3. At volume expansion of 2.32 cm^3 (i.e., time = 38.8 hr), gas bubbles grew considerably (see Fig. 5b). But, there was no gas in the cap at the top; therefore, the volume of the gas in the core is estimated to be about 1.5 cm^3. At t = 88.3 hr, volume expansion 5.3 cm^3, the gas bubbles had grown further (see Fig. 5c), and there was 0.6 cm^3 of gas in the cap at the top (see the bright space in the top of the cap). Therefore, about 0.6 cm^3 of gas had been produced from the core. Fig. 5c shows that at expansion of 5.3 cm^3, there were no gas bubbles in the bottom 2 to 3 cm of the core. Finally, at 12.9 cm^3 expansion, gas bubbles had grown all over the core surface.

At the expansion of 2.4 cm^3 (t = 40 hr), a small gas bubble was observed in the cap at the top. The volume of the gas in the cap grew to about 0.3 cm^3 at an expansion of 4.2 cm^3. Further expansion to 5.3 cm^3 yielded an increase in the amount of gas in the cap to about 0.8 cm^3. At 6.8 cm^3 expansion, there was approximately 2 cm^3 of gas in the cap. The oil recovery from solution-gas drive is equal to the gas saturation of the core; at 6.8 cm^3 expansion, about 4.8 cm^3 of oil has been produced from the core (the formation volume factor is very close to one). Therefore, the oil recovery (to an expansion of 6.8 cm^3) for the solution-gas drive mechanism is over 4 percent. Fig. 6 depicts the gas volume in the cap vs. the volume expansion for Test 4.

At an expansion of 11.26 cm^3, the amount of the oil produced into the expansion pump was measured (by compression). It was found that there was about 5 cm^3 of oil in the pump. At this expansion, the cap had already been filled with gas down to the production side arm, corresponding to about 3.4 cm^3 of gas. Similar measurements were made at further expansions. The data are shown in Table 1. This table shows that as pressure drops, oil continues to be produced from the core. The oil production from the

core is about 0.02 cm^3/psi pressure depletion, which implies that the oil mobility is significant.

The experiment was terminated at a volume expansion of about 30 cm^3. Pressures at both ends of the core were measured as a function of the time after the expansion was stopped. The pressure for the top at the termination of expansion was 248 psia. It increased to 252 psia after about 80 hours. There were small pressure fluctuations for this top end. The pressure at the bottom end, both during the test and after expansion halt, fluctuated more. Its fluctuations after expansion halt was about 5 psi and showed a decreasing trend in the period of pressure monitoring (80 hours).

The critical gas saturation for this test is estimated to be around 2.5 percent (see Fig. 6). But, oil mobility seems to be significant even after gas flow. Comparison of Tests 3 and 4 reveals much higher recovery from solution-gas drive when flow occurs from the bottom. But, even for Test 4, where the production was from the top, about 6.5 percent heavy oil recovery was achieved by the end of the test.

Light Oil

For the following two tests, a 35 API gravity oil from the North Sea was mixed with pure methane; 16.2 cm^3 of methane was mixed with 1 cm^3 of stock tank oil at standard conditions of 14.69 psia and 60° F. The bubblepoint pressure of the mixture at 77° F is around 585 psia. The surface tension at the bubblepoint is estimated to be around 15 dyne/cm.[11] Viscosity at 77° F is not available. But, the viscosity of the saturated oil at 585 psia and 187° F is around 1 cp. The measured compressibility of the light oil used in the following two tests is 10^{-5} $psia^{-1}$ (at 77° F in the pressure interval of 625 to 700 psia). The measured compressibility of the total coreholder system with single phase oil is around 2.5 x 10^{-5} $psia^{-1}$.

Test 5: 0.3 cm^3/hr Expansion Rate -- In this test, as well as Test 6, the system pressure was initially 690 psia, and the expansion from the top started from this pressure. Fig. 7 shows the pressure-volume expansion data. The same figure also shows the data from the

expansion of 120 cm^3 of oil in the pump isolated from the core system. Due to different compressibilities, Test 5 and pump results in the single liquid phase state (from 690 to about 500 psia expansion) differ by a small volume. The critical supersaturation pressure for the oil in the pump (i.e., open space) is slightly less than the corresponding value of Test 5. The growth of gas phase is, however, faster in the pump; after gas evolution, supersaturation decreases very fast in the pump.

In Test 5, around a volume expansion of 0.5 cm^3 at a pressure of 505 psia, the slope of the pressure-expansion plot changes, indicating gas evolution. Gas bubbles on the surface of the core were first visible at a volume expansion of 0.9 cm^3. The total number of bubbles was around 20 to 25. Further expansion to 1.2 cm^3 yielded an increase in the size of the existing bubbles. Fig. 8 provides the photographs of the coreholder at various times during the expansion. At an expansion of 1.2 cm^3, the bubbles are shown in Fig. 8a. This picture shows that the bubbles are distributed evenly across the core. At the expansion of 1.45 cm^3, bubbles grow further, and there seems to be one new patch of gas at the top of the core; this new gas patch could be the result of bubble growth from the inside of the core. At the 2.1 cm^3 expansion, the bubbles grow further (see Fig. 8c). The final photograph before gas flow from the core at a volume expansion of 2.7 cm^3 shows that the gas bubbles have grown considerably and may be connected (see Fig. 8d).

Visual examination of the cap at the top showed very little gas until a volume expansion of 3.3 cm^3. At this expansion, the gas in the cap started to increase with expansion. Fig. 6 shows the volume of gas in the cap vs. volume expansion for Test 5. The contribution of the gas from the oil inside the cap is very small and can be neglected. Therefore, the gas in the cap could be assumed to be the result of gas flow from the core. From Fig. 6, one estimates the critical gas saturation to be around 3 percent. Fig. 6 also reveals that during the expansion from 3.3 to 7.8 cm^3, about 1 cm^3 of oil is also produced from the core. The solution-gas drive to a volume expansion of 7.8 cm^3, results in an oil production of 3.8 cm^3, which is about 3.5 percent recovey (excluding liquid compressibility). After the gas in the cap reaches 3.4 cm^3, it would flow out to the pump

via the side arm (shown in Fig. 8). During the remaining course of the experiment at volume expansions of 8.1, 10.2, 15.0 and 22.8 cm^3, we measured the volume of the gas in the pump (by compressing the pump fluids in a short time). This allows us to estimate the oil production from the core. At expansion of 10.2 cm^3, oil production from the core was about 5.0 cm^3, but from 10.2 to 22.8 cm^3, there was very little increase in the amount of liquid in the pump. This suggests that gas mobility is very high and liquid mobility (in the core) is very low. Note that the oil shrinkage in the 600 to 400 psia range is around 1 percent.

The supersaturation for Test 5 and the pump test were measured at the end. For the pump, the pressure increased about 6 psi after halting expansion. For Test 5, the supersaturation was 8 psi. There was practically no increase in pressure after one day.

Test 6: 0.06 cm^3/hr Expansion Rate -- Fig. 9 shows the pressure-volume expansion for the last, as well as the previous, test. At about 0.5 cm^3 expansion, the pressure decline rate decreases considerably, but no gas bubbles were visible on the outer surface of the core to a volume expansion of about 0.9 cm^3. At this expansion, some 7 to 10 gas bubbles were visible on the core outer surface. From then on, these bubbles grew. The growth of gas bubbles is very similar to Test 5. The only difference is that the number of bubbles in Test 6 is less than that in Test 5. As Fig. 9 reveals, a major difference between Tests 5 and 6 is the high supersaturation of the latter test at the early stages of gas bubble growth.

Until an expansion of about 3 cm^3, no sizeable gas phase was visible in the cap at the top of the core. From this expansion, gas volume in the cap increased. Fig. 6 shows accumulation of gas in the cap. At an expansion of 4.0 cm^3, about 1 cm^3 of gas is present in the cap, which is mainly the result of gas flow from the core. The amount of gas in the cap increased to 3.4 cm^3 at an expansion of 6.7 cm^3. Further expansion resulted in the flow of the gas from the side-arm to the pump. In the expansion period of 3.0 to 6.7 cm^3, only 0.5 cm^3 of oil was produced from the core.

At expansions of 11, 14 and 17 cm^3, the amount of the gas in the pump was measured and then the oil production from the core was estimated. We estimate that at 11 cm^3 expansion, total oil production from the core is about 4 cm^3. At later expansions, there was negligible oil production from the core. Therefore, the total oil recovery at the termination of the test is around 4.2 percent. The critical gas saturation for this test is estimated as 2.5 percent. Therefore, both the critical gas saturation and the recovery (at the same expansion) for Test 6 are less than for Test 5.

At the end, the supersaturation was measured. Over a period of one day, the pressure increased from 438 to 442 psia, which gives a supersaturation of about 4 psi for the end of expansion.

DISCUSSION AND CONCLUSIONS

An important issue in the interpretation of the experiments described above is whether the number of bubbles visible on the surface of the core represent the bubble density within the core. Based on the following reasoning, we believe the number of bubbles on the core surface and within the core are related. In the design of the coreholder, the core was tightly sealed with a heat-shrunk teflon sleeve and the overburden pressure was kept at a pressure of at least 200 psi higher than the pressure inside the core. Measurement of the permeability of the core within the setup and outside gave the same permeability. In addition, the teflon does not wet the liquid, and nucleation active sites are not believed to be initiated from the teflon surface.

The most important conclusion of the work is that solution-gas drive for a heavy oil in porous media can be a very efficient process. The bubble density (number of bubbles per unit area or volume) is very high. Due to high oil viscosity, the pattern of bubble growth may be such that gas mobility is low; consequently oil mobility may be appreciable. Recovery of 10 percent of heavy oil with a bubblepoint pressure of 445 psia (Test 3) to a pressure of about 320 psia from solution-gas drive is an indication of high recovery efficiency. Some authors refer to the type of heavy oil used in our work as foamy oil.[4] From our visual observations, all we observed was high bubble density and a pattern of gas bubble growth which was different for a light oil.

Other major conclusions drawn from this work are:

1. Critical gas saturation is a measureable quantity.
2. The number of nucleated bubbles is a function of the rate of pressure decline; the higher the rate of pressure decline, the higher the number of bubbles.
3. The measured critical saturation for the fluids and rock of this work are in the range of 0.5 to 3 percent.
4. The nucleation in porous media is an instantaneous nucleation process.

Conclusions 2 and 3 are in line with the theoretical results presented in Ref. 1.

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Table 1. Gas and Oil Production Data for Test 4

Time, hr	Expansion, cc	Oil in Pump, cc	Gas in Pump, cc	Oil from Core, cc	Closed Side Pressure, psia	Expansion Side Pressure, psia
187.7	11.26	8.35	2.91	4.95	356	346
238.3	14.30	8.77	5.53	5.37	340	324
327.8	19.67	9.43	10.24	6.03	311	293
375.5	22.53	9.50	13.03	6.10	296	269
495.3	29.72	10.05	19.67	6.65	269	248[1]

Figure 1. Apparatus diagram for critical gas experiments.

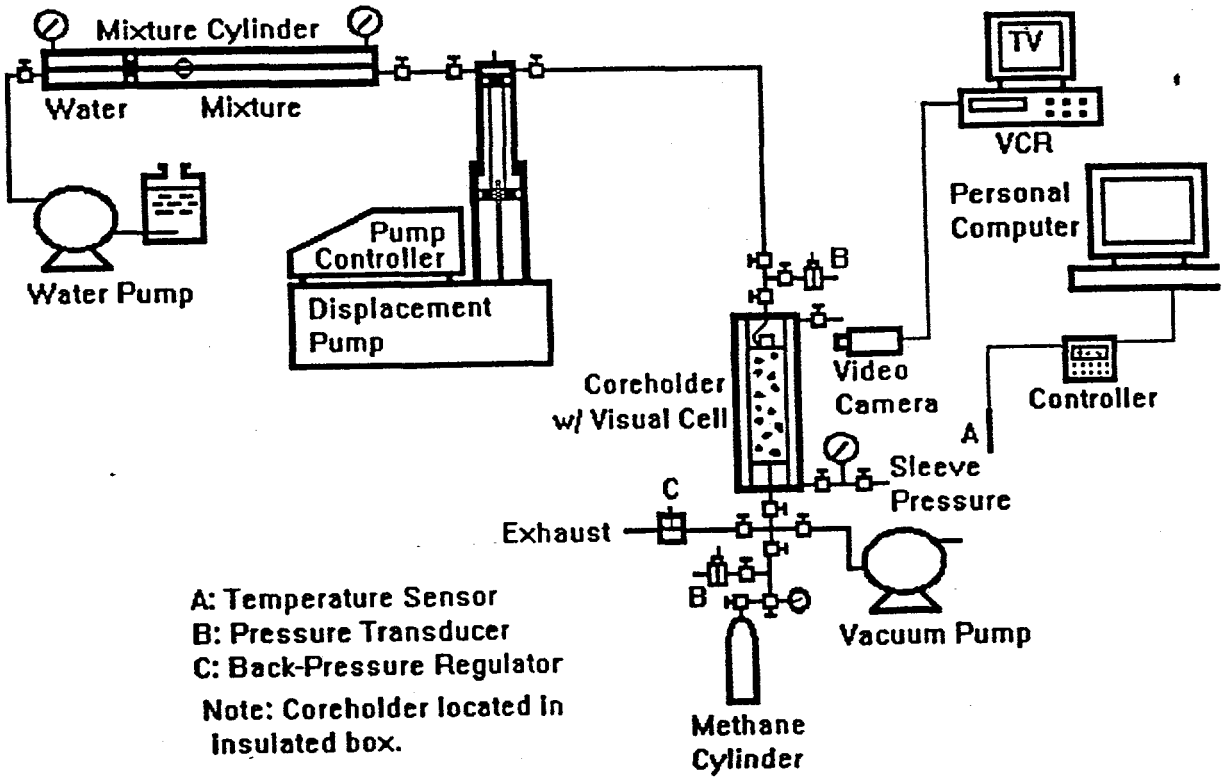


Fig.2-Pressure-volume expansion data for Tests 1 and 2.

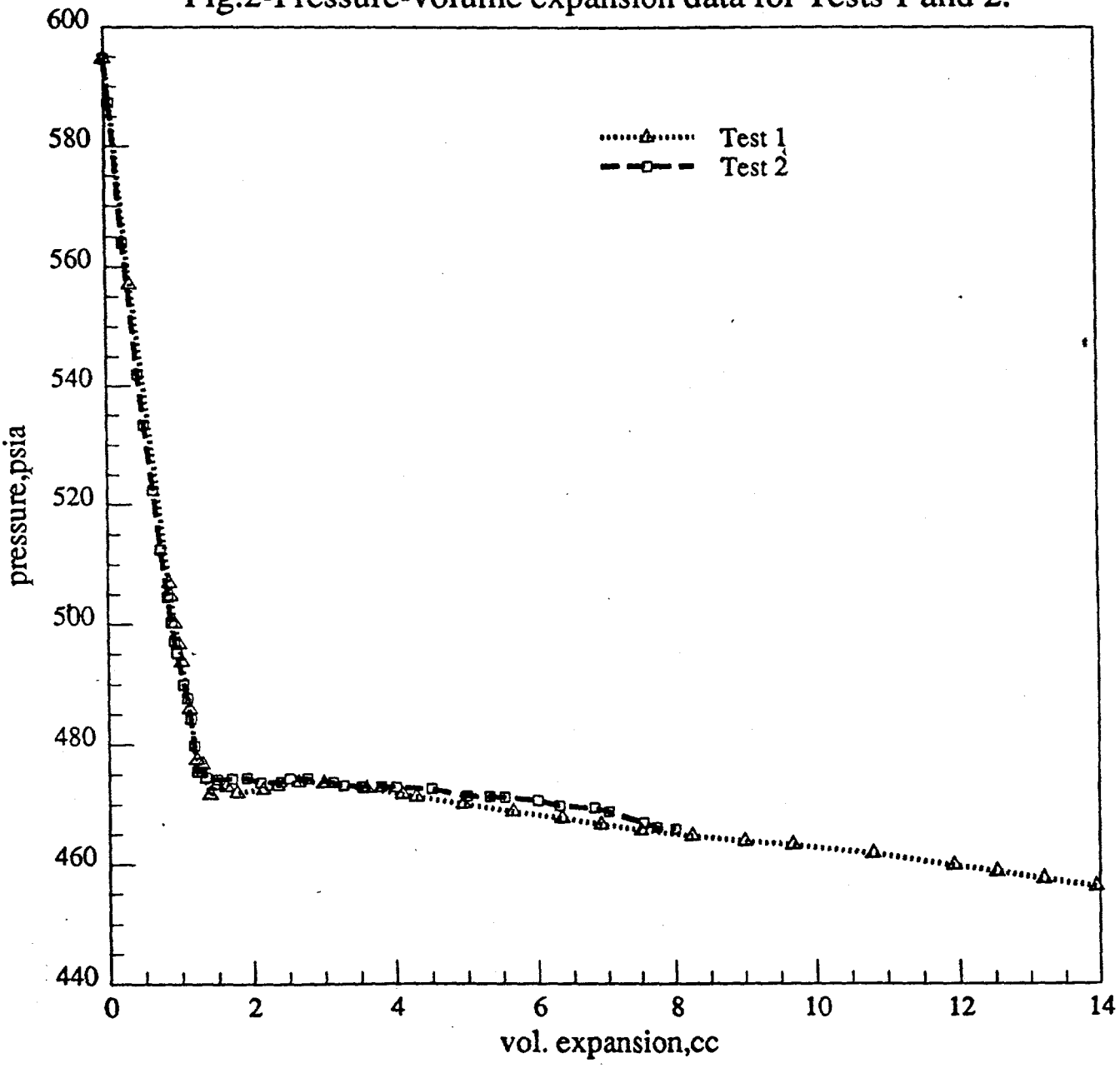


Fig.3-Pressure-volume expansion data for Test 3.

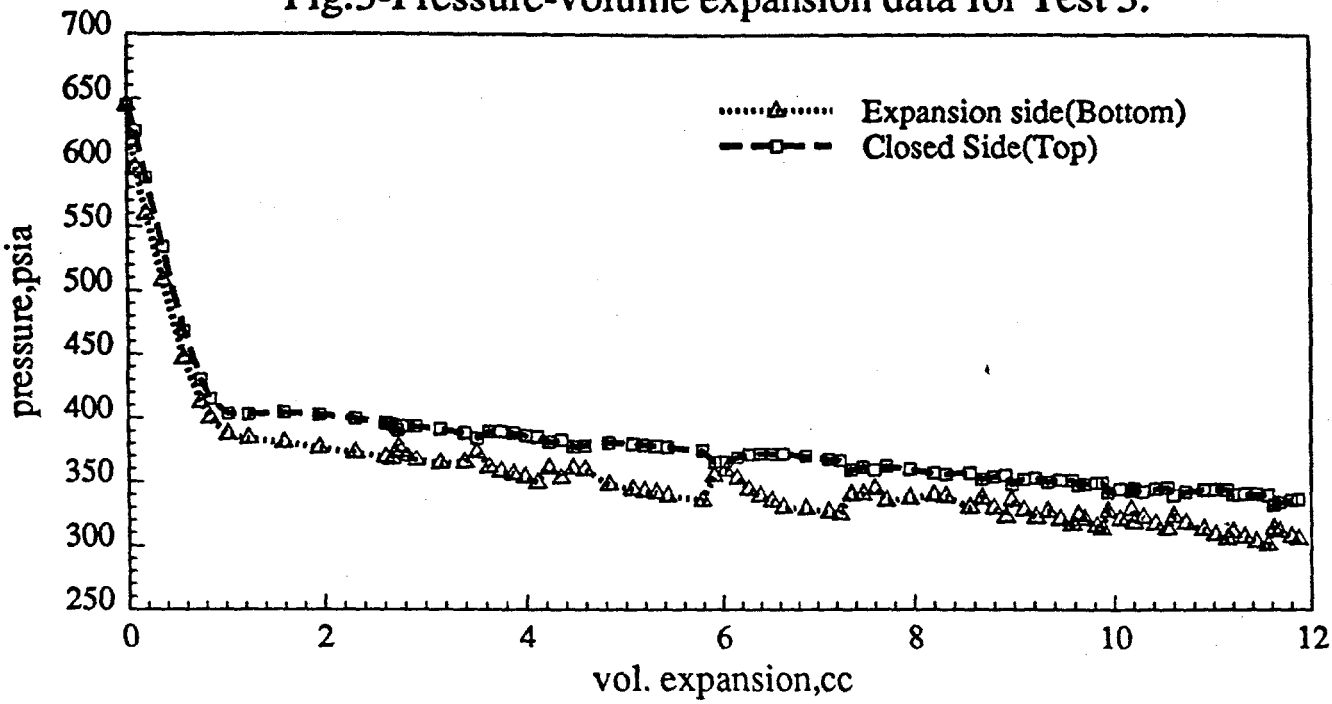
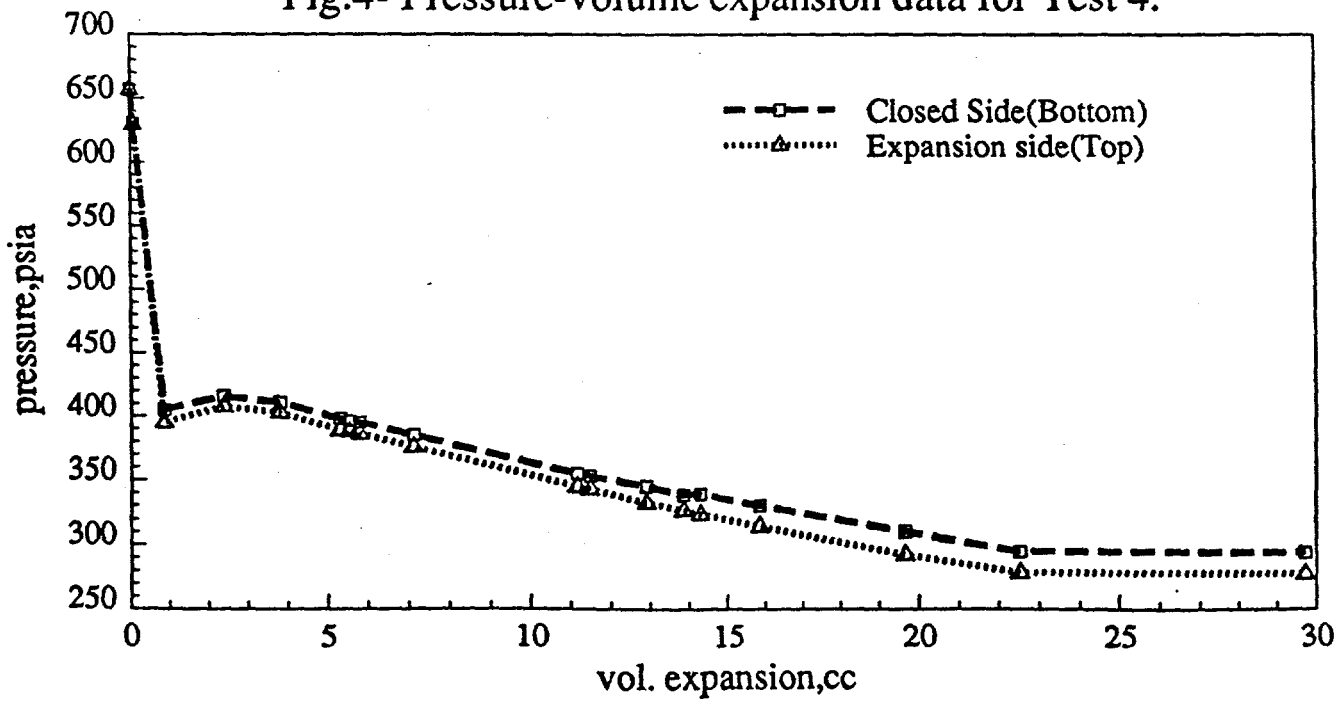
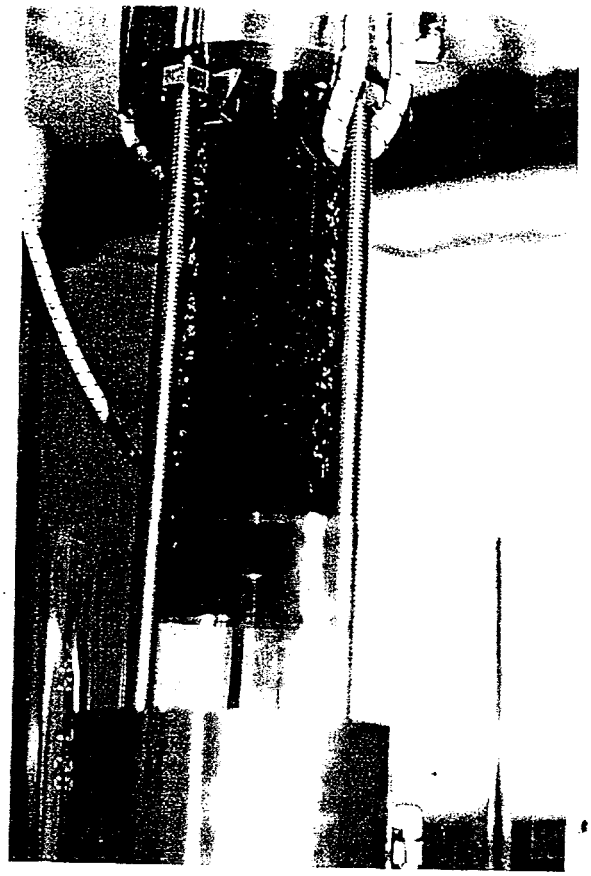


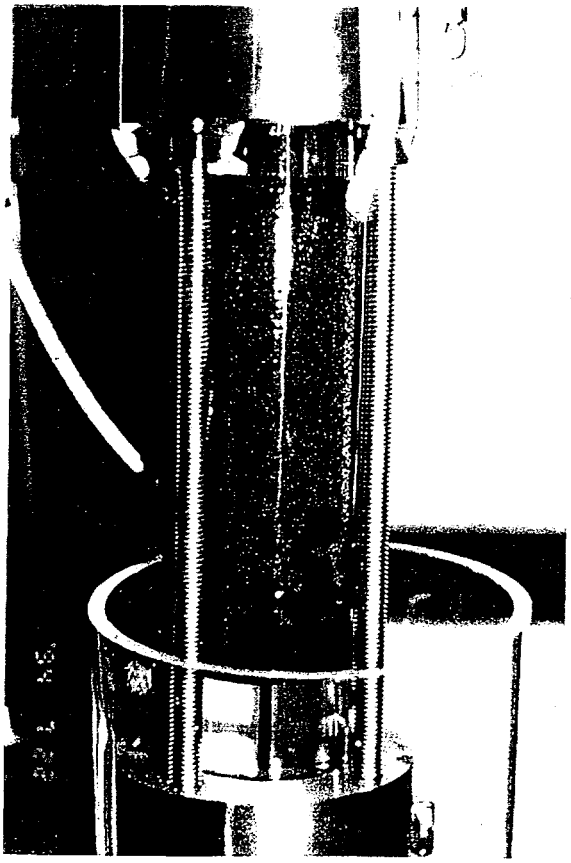
Fig.4- Pressure-volume expansion data for Test 4.



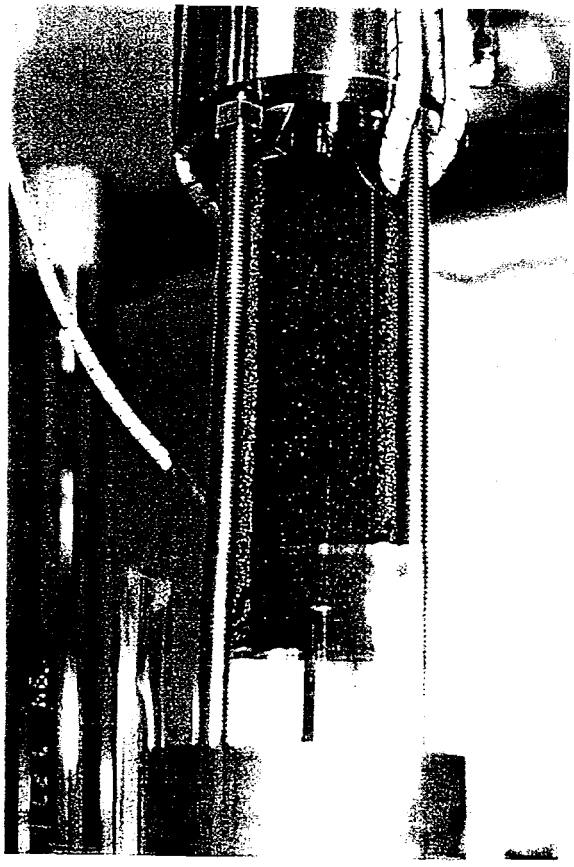
(a) expansion= 1.28 cc



(b) expansion= 2.32 cc



(c) expansion= 5.30 cc



(d) expansion= 12.9 cc

Fig. 5- Growth of gas bubbles at various expansions for Test 4.

Fig.6- Gas production from the core into the top cap.

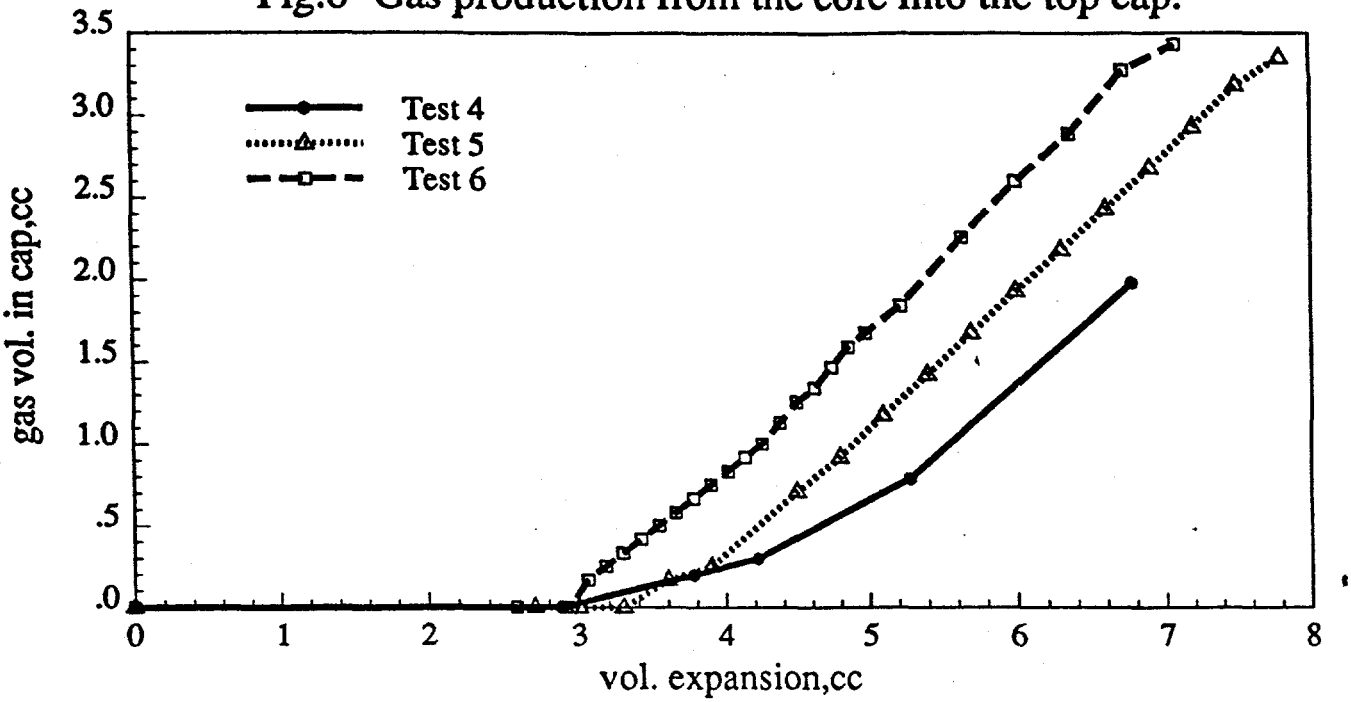
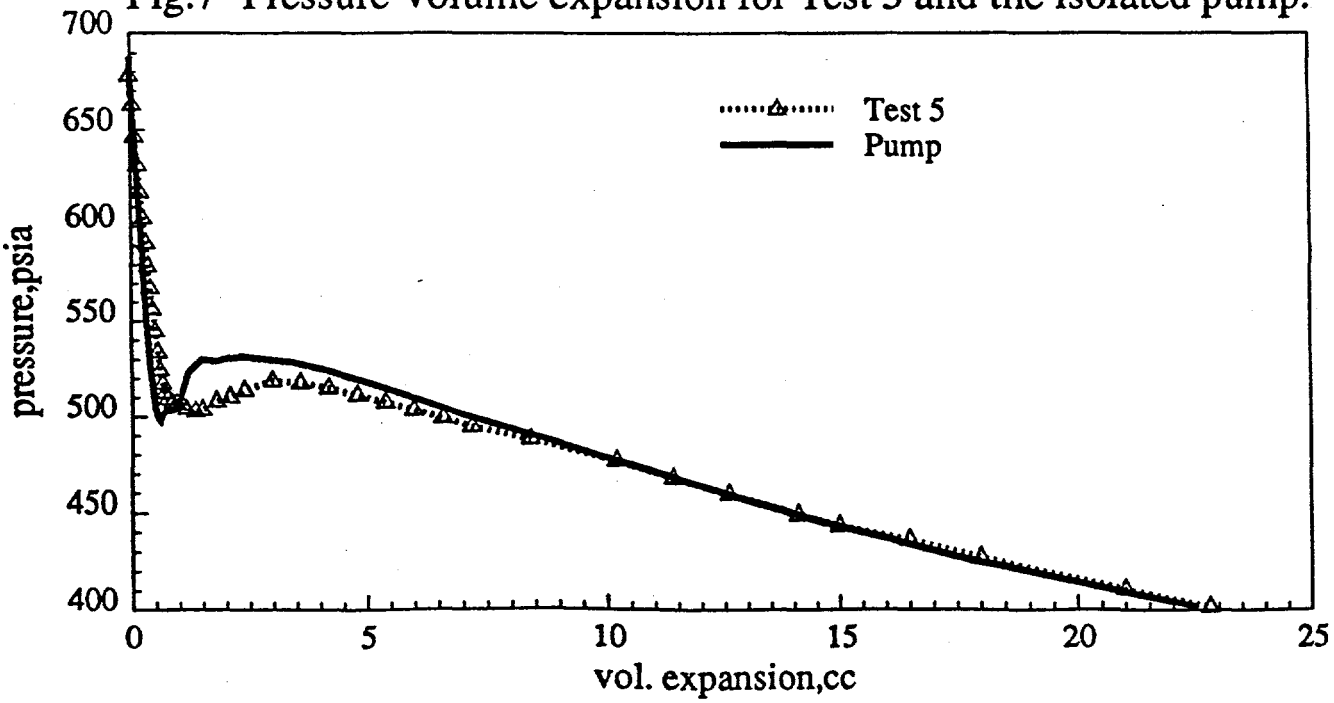
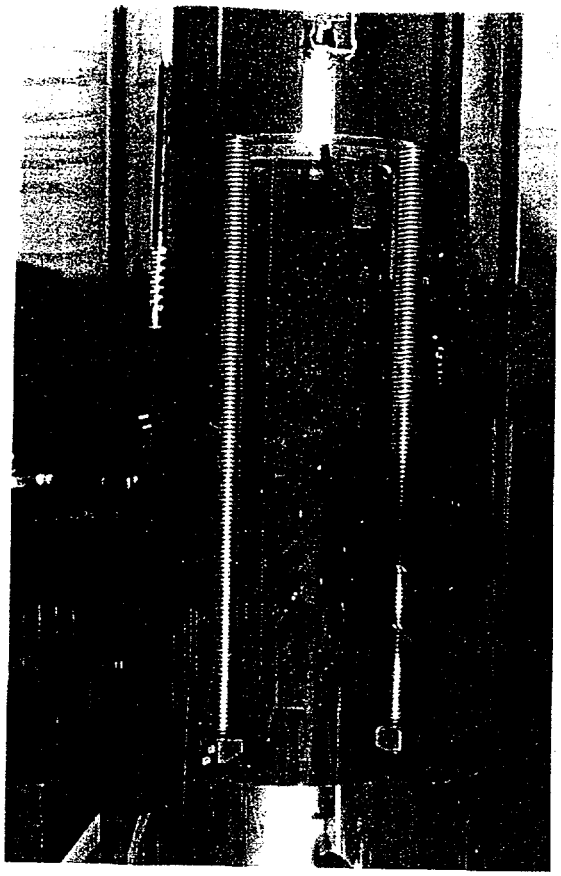
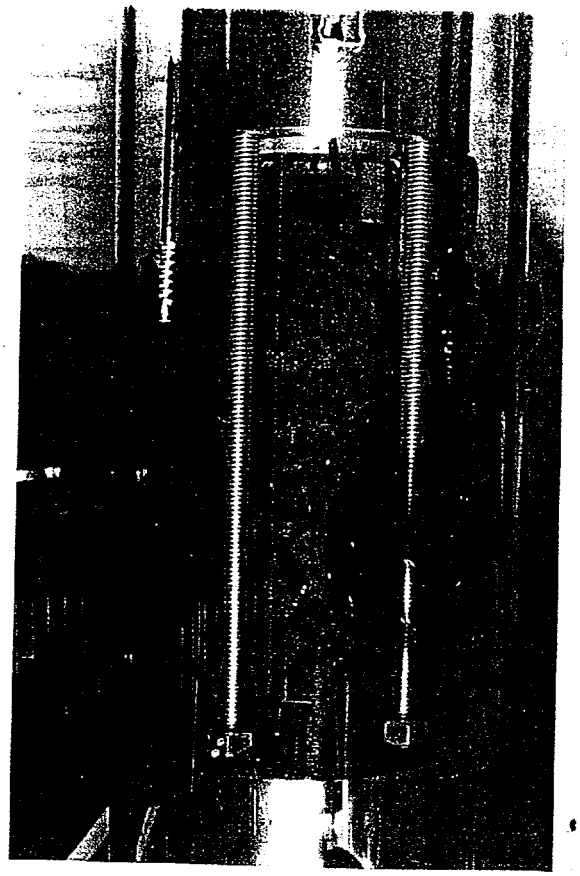


Fig.7- Pressure-volume expansion for Test 5 and the isolated pump.

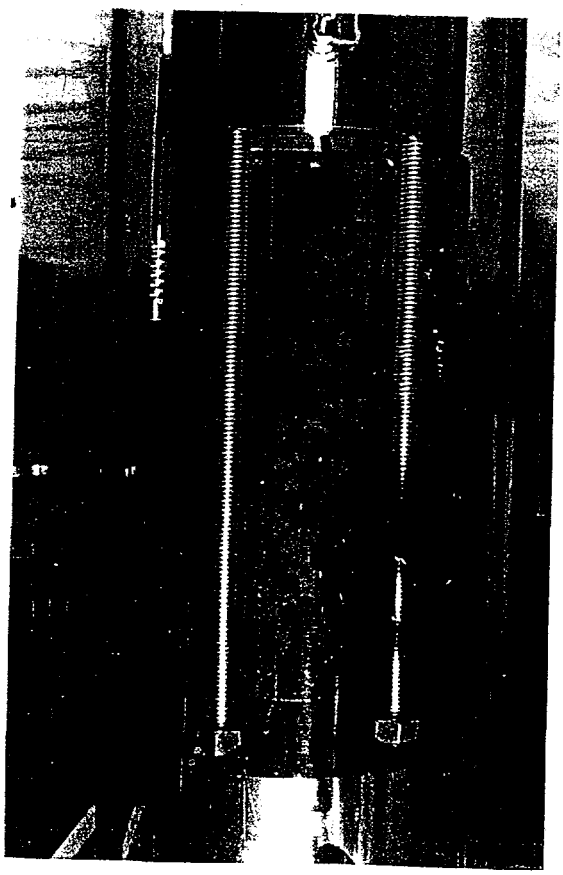




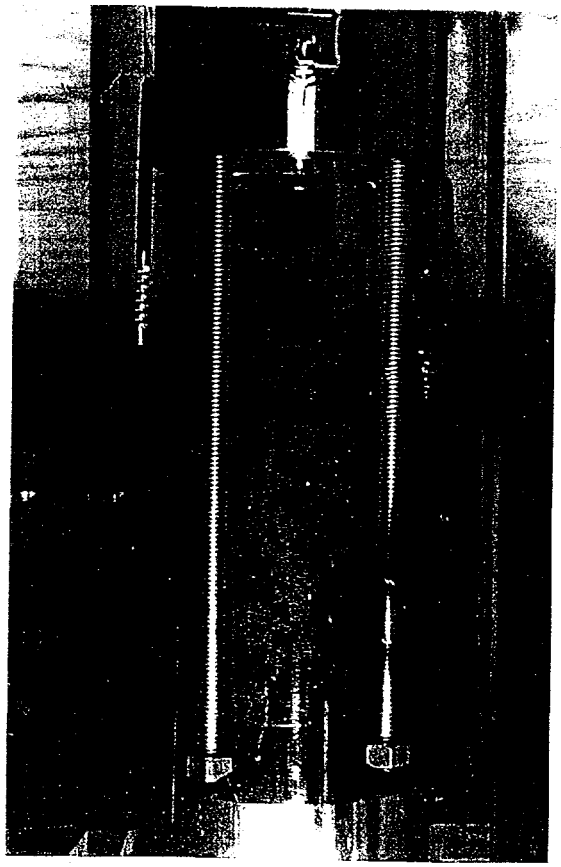
(a) expansion= 1.20 cc



(b) expansion= 1.45 cc



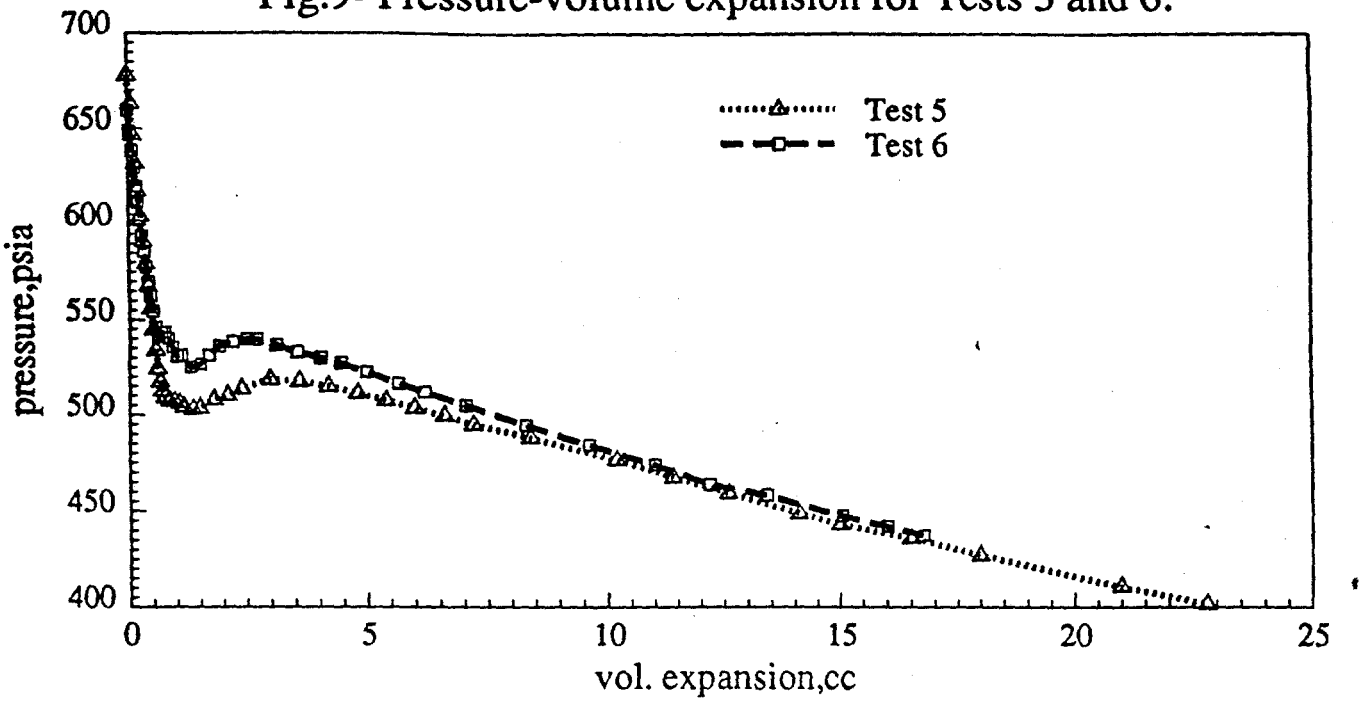
(c) expansion= 2.10 cc



(d) expansion= 2.70 cc

Fig. 8- Growth of gas bubbles at various expansions for Test 5.

Fig.9- Pressure-volume expansion for Tests 5 and 6.



RESERVOIR ENGINEERING RESEARCH INSTITUTE

PROJECT 6c - WATER INJECTION IN FRACTURED/LAYERED POROUS MEDIA

An Experimental Study of Water Injection in Fractured Porous Media

1Q.95

January 1 through March 31, 1995

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Ross Hackworth

INTRODUCTION

In certain fractured reservoirs the recovery from water injection has been very efficient. The performance of a fractured reservoir to water injection to a large extent depends on the matrix capillary pressure including the residual oil to water at high negative capillary pressures. In both fractured and layered reservoirs, capillary pressure could provide an excellent driving force, depending on dPc/dSw and on the magnitude of the capillary pressure. This report provides our first effort towards the understanding of water injection in fractured and layered reservoirs. Future reports will include literature review and a detailed descussion of water injection mechanisms.

Two experiments have been performed on an aggregate of matrix slabs. In this report the results will be presented.

EXPERIMENTAL

The fractured porous media used for the experimental investigation consists of a stack of 12 Berea slabs, three layers of four blocks each. Fig. 1 shows the matrix slabs and the configuration of the fractured porous media. All the matrix slabs are aligned in the same direction. The core system is enclosed by glass plates on the sides, and on the top and bottom are aluminum plates with many holes to distribute the flow into and out of the system evenly. The configuation of the slabs is identical to that previously used in miscible displacement experiments.[1] Plumbed to the bottom of the core is an Eldex B-100-S chromatography pump, used for the water injection. The top of the system is connected to a tube which terminates in an inverted graduated cylinder used for measuring the production of the oil phase. A diagram of the apparatus is shown in Fig. 2.

The core system was evacuated at approximately 100 mTorr for a week prior to saturation with normal decane (nC_{10}). The pore volume of the system measured via volume of nC_{10} used for saturation is estimated to be 8800 cm^3. The brine used for displacement consists of 1 wt% NaCl and distilled water.

RESULTS AND OBSERVATIONS

Two tests were performed. The only difference between the two is the injection rate.

Test 1. The injection rate used for Test 1 is approximately 150 cm^3/hr. A plot of the volume of nC_{10} produced versus the volume of brine injected is shown in Fig. 3. From the plot it can be seen that the production of oil follows the injection rate up to a volume of about 4200 cm^3 (~28 hr), where water and oil are seen in the production line. This is when water breakthrough occurs. Therefore, the recovery at breakthrough is around 48%. A transition period occurs for the next 20 hours, when the oil production rate continues to decrease to a steady state rate of 6 cm^3/hr. The commulative oil production at this time is about 5000 cm^3 (or 57% PV). At an injection of 15000 cm^3 (~1.7 PV) water, the injection was curtailed and imbibition was allowed to proceed for about 3 days. The water injection was then resumed. A brief period of pure nC_{10} production (~30 cm^3) was observed, after which the system returned to a very slow production rate.

Test 2. The injection rate for this test is about 198 cm^3/hr. The volume of nC_{10} produced versus the volume of brine injected is also shown in Fig. 3. This figure reveals that the results from the two tests are very similar. For Test 2, the production of oil follows the injection rate up to a volume of about 4200 cm^3 (~21 hr), where water breakthrough occurs. In the two-phase production period of the next 15 hours, the oil production rate continued to decrease to a steady state rate of about 6 cm^3/hr. The cumulative production at this time is about 5000 cm^3 (~57% PV), which is the same as Test 1. At an injection of 18200 cm^3 (~2 PV) water, the injection was curtailed and imbibition was allowed to proceed for about 4 days. The water injection was then resumed. A brief period of pure nC_{10} production (~28 cm^3) was observed, after which the system returned to a negligible production rate.

Fig. 4 shows the gravity drainage performance of the same system where air replaces the drained nC_{10}. The results show that after a brief period of about 3 hours, the rate of drainage decreases to less than 100 cm^3/hr. The cumulative production after 14 days is close to 3800 cm^3 (~0.43 PV), which is substantially less than the results from water injection at breakthrough.

CONCLUDING REMARKS

Water injection in the fractured configuration of Fig. 1 seems to be effective in oil production. However, in order to understand the process, the results should be interpreted by a theoretical model or a numerical simulation.

REFERENCE

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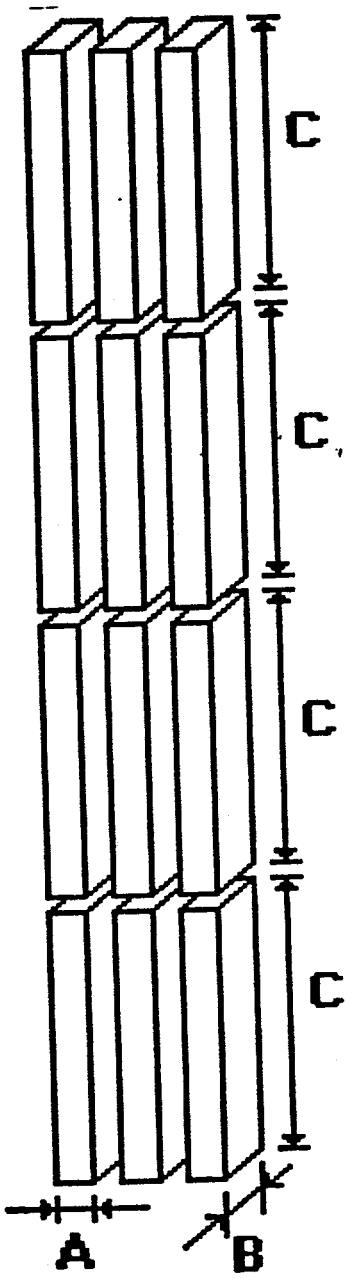
Fig. 1 - Matrix Slab Arrangement Used for Water Injection



A=4.89 cm

B=14.95 cm

C=45.53 cm

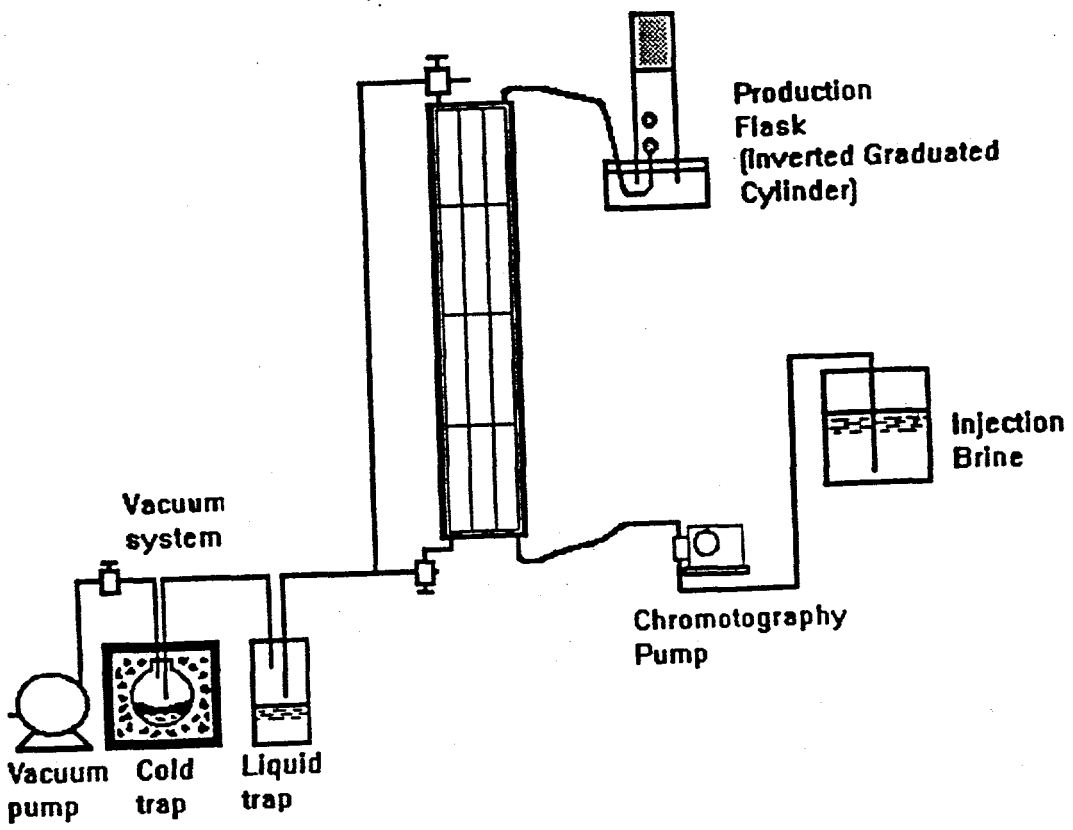


Fig. 2 - Apparatus Schematic

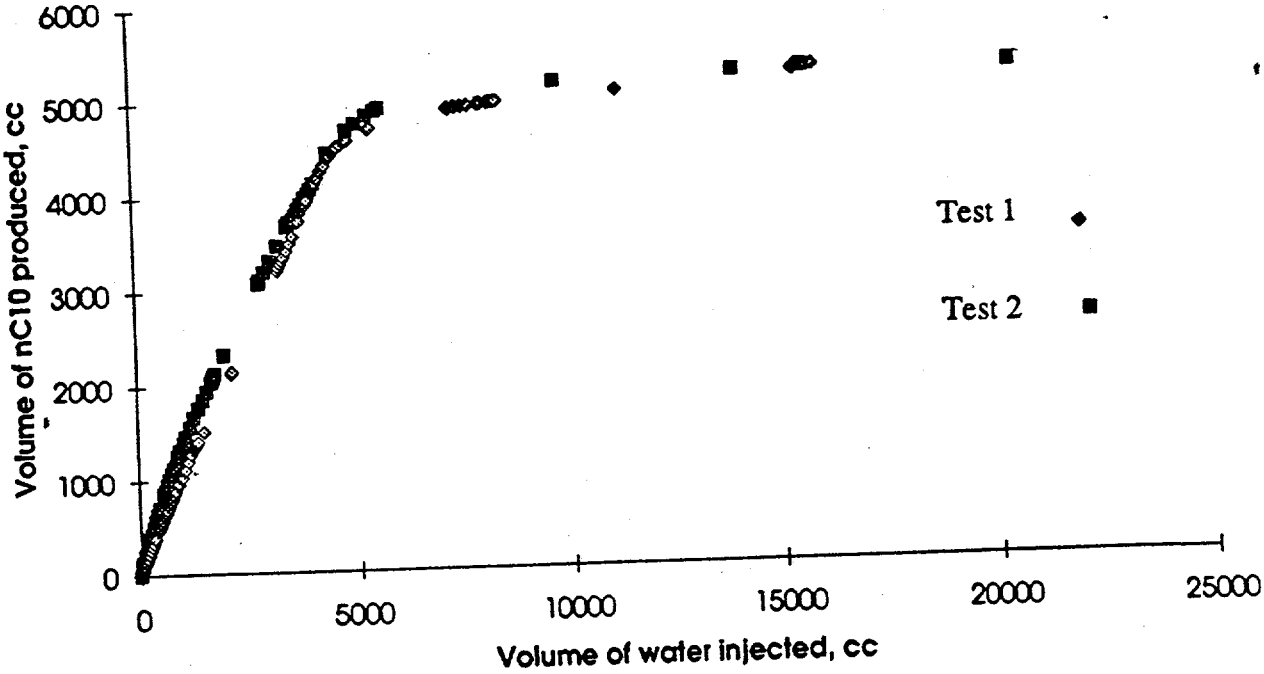


Fig. 3 - Volume of Water Injected v.s. Volume of nC_{10} Produced for Tests 1 and 2

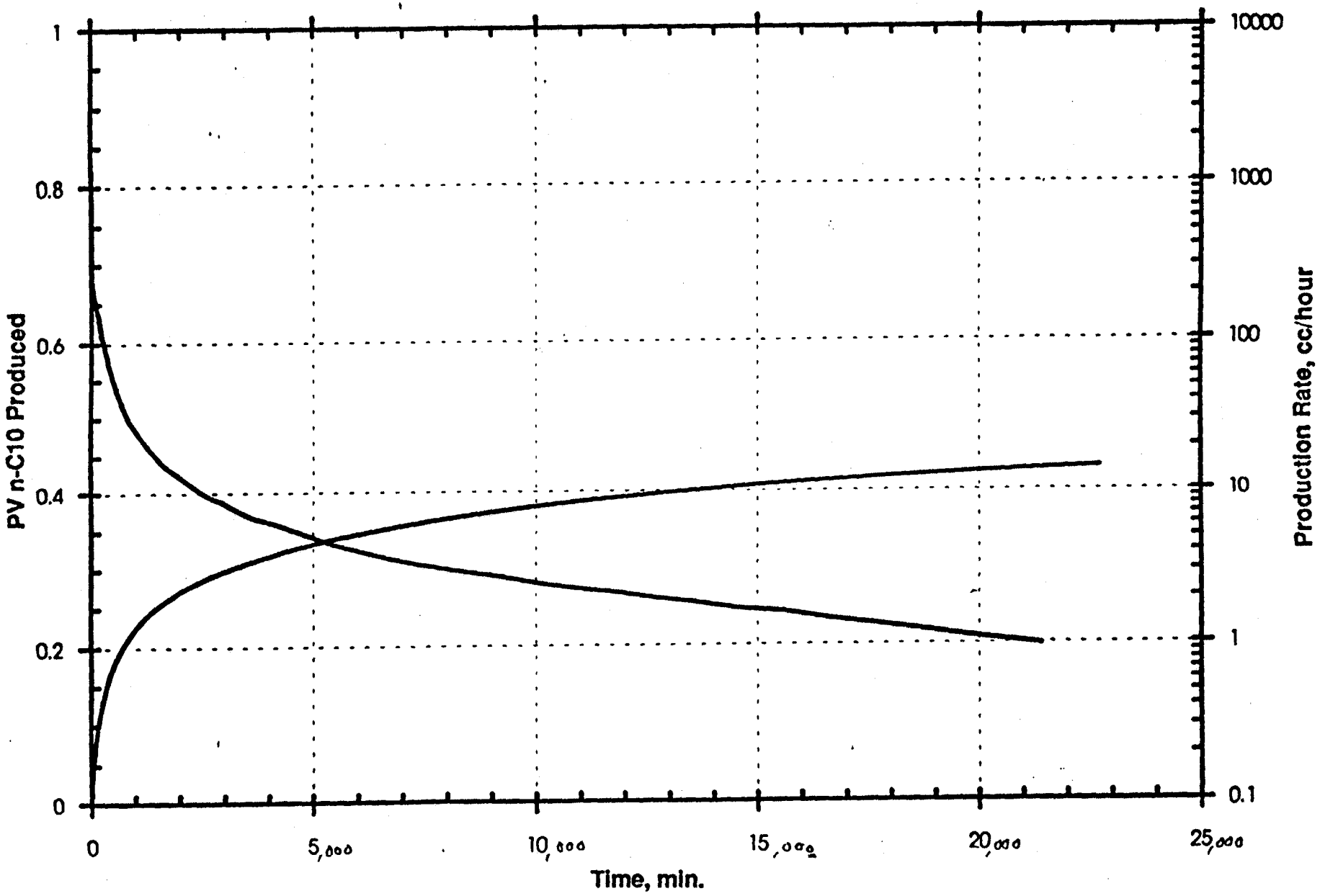



Fig. 4 - nC_{10} Produced v.s. Time for Gravity Drainage