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APPLICATION OF ENHANCED RECOVERY

TO THE MOONIE OILFIELD, QUEENSLAND

by

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## SUMMARY

The Moonie oilfield of south central Queensland was discovered in 1961, and is now nearing depletion after producing over 35 percent of original oil in place. The field has interesting potential for enhanced recovery because of its reasonably high residual oil saturation, high gravity oil and several other factors. The main detriment towards enhanced recovery is the edge water drive from the northwest to the southeast of the field.

The Bureau of Mineral Resources through the Petroleum Technology Laboratory has conducted studies on core samples from the field using polymer as an enhanced oil recovery agent. The tests were conducted at various water cuts to simulate different stages of depletion and water throughput in the reservoir. Studies were also conducted to evaluate the effect of permeability variation on "polymer oil" recovery (manifold tests) and the effect on recovery of polymer dilution by edge water influx.

The tests showed that polymers can produce a significant amount of additional oil at depletion, ranging from 0.8 to 7.7 percent of oil in place, and particularly when some mobile oil is present in the reservoir. The manifold tests showed a significant reduction in flow through the higher permeability samples on polymer introduction, which substantially improved oil displacement in the tighter material; "diluted" polymer still produced some additional oil.

Residual resistance tests involving the measurement of flow to water before and after polymer injection showed marked reductions in water permeability, particularly in samples with low flow capacity; however, reductions in flow capacity to oil at low water cuts after polymer injection were minimal.

## 1 Introduction

### Application of Enhanced Recovery to the Moonie Oil Field, Queensland

The Bureau of Mineral Resources, as part of ongoing studies to encourage exploration and development of the nations mineral resources has initiated studies in enhanced petroleum recovery in some of our depleting reservoirs. The initial investigations in this field have examined one of our oldest oil fields - the Moonie reservoir in Queensland. The work was conducted in conjunction with the Queensland Mines Department and International Oils Ltd who are operators in the field.

Oil recovery from subterranean reservoirs by natural depletion is a rather inefficient process which generally leaves much more oil trapped in the reservoir than is recovered. For instance, recovery efficiency by natural water drive may vary from a maximum of 80 percent of oil in place in a few reservoirs, to as low as 30 percent, with the majority of reservoirs producing on average about 45 percent of oil in place. Reservoirs producing by a dissolved gas drive mechanism may only recover from 10 percent to 30 percent of oil in place (1).

Under a water displacement mechanism oil entrapment usually occurs as a result of two controlling factors

(1) Areal sweep efficiency

(2) Displacement efficiency.

Sweep efficiency is governed by the uniformity of a formation (lenses, channels, fractures etc usually contribute to poor sweep efficiency) and also by the fluid mobility ($\frac{K}{U}$) which is the permeability of oil or water in a reservoir divided by its viscosity. High mobility ratios ($Kw/Uw \cdot Uo/Ko > 10$) indicate poor sweep efficiency in a reservoir.

Displacement efficiency is dependent on the microscopic pore displacement where capillarity and surface/interfacial tensions control production rather than dynamic forces as in macro sized pores. Reservoirs showing a very even pore size distribution usually show good displacement efficiency under water drive due to the even flood front movement, whereas the reverse is true for an uneven pore system. Most of the oil unrecovered after water displacement is trapped in these micro pores as unconnected globules and droplets by poor displacement efficiency (2).

It is toward this residual oil that improved recovery techniques are generally directed. Studies are currently being conducted in many areas of the world (including Australia) to attempt to win more of these unrecovered hydrocarbons by enhanced recovery techniques.

## 2. The Moonie Oil Field

Moonie is a typical example of an oil reservoir in Australia which may have application for enhanced recovery. The field is located in the south-central part of Queensland (Figure 1); it was initially discovered in 1961 by a consortium headed by Union Oil of California. During early field exploration, oil was discovered in two zones in the field, at about 1720 metres ($50^{\circ}$ API gravity oil) and 1780 metres ($44^{\circ}$ API). The lower zone later proved to be the principle producing horizon, with only two wells producing from the upper sand.

The lower producing sand has an average permeability of 300 millidarcies, 18 percent porosity and an original water saturation of about 47 percent. The original in place reserves of the field were about 54 million barrels, with the main production mechanism being edge water drive moving from northwest to southeast.

## 3. Production History at Moonie

The Moonie field peaked in oil production in 1966 when 9000 barrels per day were produced. This declined rapidly and production is now about 900 barrels per day with water production exceeding 90 percent of the producing stream. The original oil-water contact was relatively flat across the field but is currently tilted towards the southeast where water cuts are less severe. There is also a variation in the water table in the north east of the field where production problems exist apparently due to localized clays; oil production in that part of the field has only averaged about 9 percent of oil in place while average recovery in the south-western part of the field is about 42 percent of oil in place. This latter recovery compares favourably with world averages for a water drive reservoir (1).

4. Application of Enhanced Recovery to the Moonie Field

At depletion, the primary recovery in Moonie is calcaluated to be about 20 million barrels, leaving about 34 million barrels trapped in the reservoir. This represents a field wide recovery of only 37 percent of oil in place. How can more of this very valuable residual oil be recovered? For instance, if an enhanced technique could be devised to recover an additional 5 to 10 percent of the oil in place at Moonie, this could enable a further 2.7 to 5.4 million barrels of oil production, representing a saving in foreign exchange of 37 to 74 million dollars at world parity pricing.

In order to evaluate possible enhanced recovery applications, it is first important to determine the controlling factors on Moonie production. Moonie is a heterogeneous type sandstone in which the main production has been due to movement of fluids along the bedding planes from west to east under edge water drive, with little effect from vertical flow perpendicular to bedding. There is some probability that "channeling" of water through the more permeable zones and stratified layers has occurred, with bypassing of oil in unflushed zones. This is suggested in the wide variations in permeability in adjacent samples, although the current recovery (42 percent of oil in place) in the south western part of the field suggests reasonably uniform displacement. With uniform displacement, one could consider that residual oil would be trapped in the micro system rather than in extensive "pockets" due to widespread poor sweep efficiency, not considering any radical changes in well spacing to improve sweep.

The low recovery in the north of the field (covered by wells 3, 10 and 30) suggests a probable formation damage problem which may require some form of a proven pretreatment (e.g. clay stabilization) before any enhanced recovery mechanisms can be considered. Certainly, the very high residual oil saturation for this area suggests an additional oil recovery target well worth considering, and which may entail a separate study by our laboratory.

Therefore, considering all factors, a number of enhanced recovery processes were examined for Moonie (Figures 2 and 3) and for various reasons, most were not suited. For instance, thermal techniques are of no avail because of the high gravity of Moonie crude; gas cycling, wet gas and $CO_2$ injection have little economic prospect because of the dearth of available injection fluids in the area. Similarly, solvent flooding using miscible fluids such as alcohols, LPG etc. have minimal application because of the poor vertical movement of fluids in the Moonie reservoir.

There are however some favourable advantages for chemical flooding (surfactant-micellar, polymer injection) in the Moonie reservoir. These advantages include a clean formation, fresh water, good porosity and permeability and a favourable residual oil saturation trapped at depletion. The major unknown is of course the edge water drive and its limiting factors on the desired concentration of injected chemicals. For this reason the highly capital intensive surfactant/micellar technique was deleted from further study. This decision was further influenced by Mungan (3) who says "The surfactant/micellar process is most complicated, and expensive, and chances of recovering additional oil economically are small at this time".

The expected advantages in using polymer injection as an enhanced oil recovery technique at Moonie are likely to be:

(1) Improve the general sweep efficiency by lowering the permeability in the stratified and high permeability pore channels, causing more water to flow through and displace oil from the higher residual oil zones.

(2) Significantly lower relative permeability to water and reduce water-oil ratios.

(3) Stabilize clays in the formation.

(4) Reduce mobility ratios.

The principle of displacement would be to inject polymer into wells paralleling the western boundary of the Moonie field. Oil production on the eastern margin would hopefully be augmented by the above favourable aspects and by the expected linear northwest to southeast flow of fluids in the field.

## 5. Laboratory Study - Preparation and Testing

A prerequisite to any field pilot study of enhanced recovery is a series of laboratory tests using field cores and fluids. These were carried out on cores from six wells in the southwest of the Moonie field, comprising wells 4, 9, 13, 26, 27 and 34. Initially oil recovery at natural depletion was evaluated in each of the samples by basic waterflood tests followed by polymer displacement in the same samples at various stages of oil depletion (Series 1 samples). Because of problems with wettability in these samples, additional tests over some of these same intervals were conducted on duplicate and triplicate adjacent plugs (Series 2 samples).

(a) Preparation

In preparation for laboratory work, two core samples were drilled from each piece of core parallel to the bedding planes. These comprised a $1\frac{1}{8}$-inch diameter plug for displacement recovery tests and a $\frac{3}{4}$-inch diameter plug for capillary pressure/residual water saturation tests. All plugs were trimmed to approximately $1\frac{1}{4}$ inches in length, then cleaned with toluene and dried at 105°C for 24 hours. This resulted in 69 plugs from 6 wells. Routine measurement of porosity to air and permeability to dry nitrogen was then carried out in each sample and is presented in Table 1.

(b) Capillary Pressures

In preparation for subsequent testing, all samples were saturated with Moonie field water, the analysis of which is shown in Table 2. Air-water capillary pressure tests were then initially conducted on the $\frac{3}{4}$ inch diameter plugs by the centrifugal technique; from these, residual water saturations vs. capillary pressure curves were determined on each sample for the full oil column of the Moonie structure. The curves were averaged on the basis of sample permeability and also plotted as a function of height above the oil water contact in each well. These results are shown in Figures 4 to 7 and in Table 1. Because of the dearth of samples from wells 9 and 13 (3 in each) only the individual sample results for each plug in these wells are shown in Table 1.

(c) Waterflooding (Series 1 samples)

In preparation for water displacement oil recovery tests, the adjacent $1\frac{1}{8}$ inch diameter plugs were flushed with refined oil to establish irreducible water saturations corresponding with their adjacent capillary pressure plug. Subsequently, permeability to oil at irreducible water saturation was measured, followed by a waterflood to 100 percent watercut, using a water-oil viscosity ratio comparable to Moonie reservoir conditions (0.47)

The results of these tests are shown in Tables 1 and 3 and in Figures 8 to 13 (average recovery curves for each well).

(d) Polymerflooding (Series 1 samples)

For polymerflooding, the plugs were extracted, dried and resaturated with water and oil to the same conditions existing prior to waterflooding. This was done in order to directly compare the basic flood tests with the polymerflood tests. Waterfloods were then conducted to approximately 93 percent water cut in some of the samples (simulating the current depletion state of the Moonie reservoir) and to 100 percent water cut in the balance. Following this, approximately 0.3 to 0.7 pore volume slugs of 500 ppm polymer solution (0.05% polymer by weight in distilled water) was injected into the samples, followed by water flooding to 100 percent water cut. The polymer used was a partially hydrolyzed polyacrylamide designated "Pusher 700" and marketed by Dow Chemical Company in U.S.A. Other polymers were considered, such as the polysaccharides and additional brands of polyacrylamides; however, the pusher series was chosen as a test standard because of its wide use by industry, particularly in the U.S.A.

A diagram of the apparatus used for the flood tests is shown in Figure 14. The all glass and plastic system used for the fluid reservoirs and lines/end plugs was adopted to avoid any chemical degradation of the polymer during flow tests. Mercury was used as the pressure medium as it showed minimal detrimental effects on the polymer viscosity over a one week test period. Precautions against degradation of the polymer by light were also taken by storage of fresh mixed polymers in amber bottles and the use of opaque glass reservoirs plus frequent replacement of the polymer in the flow system.

A "screen factor" apparatus used to evaluate the viscosity characteristics of the polymers is also shown in Figure 14. The use of this apparatus simulates the flow properties of polymer in a complex porous medium by virtue of the 100 mesh screens, much more appropriately than a capillary viscometer in which latter instrument the visco-dilatency of a polymer upsets true viscous flow determinations.

(e) Wettability Effects

During the course of preparing the samples for the initial polymer flood tests, problems were encountered with the wetting properties of the samples, such that duplication of oil recovery characteristics in duplicate standard water flood tests (on the same sample) could not be achieved. The cause of these wetting changes which invariably and substantially reduced oil recovery in the second flood tests is unclear. Possible causes of this reduction in recovery may be due to wetting changes from the clays in the samples or possibly as a result of the oils or solvents used during preparation and testing. As a result of these problems, "polymer oil" is shown only for those samples which were waterflooded to 100 percent watercuts (and subsequently polymerflooded); these results are shown in Table 4.

Because of the detrimental effect on evaluation of true polymer oil recovery (particularly at water cuts less than 100 percent) extra sample sets of $1\frac{1}{8}$ inch diameter core plugs were drilled from additional Moonie core material, adjacent to some of the series 1 plugs. These samples were cleaned and dried, then saturated with oil and residual water as previously described. One of these samples was then used to determine "basic" oil recovery by water flooding to 100 percent water cut, followed by polymer flooding. These results were compared to oil recovery in adjacent plugs waterflooded to less than 100 percent water cut and followed by polymer displacement. The results of all the above test work is presented in Figures 15-22 and Tables 5 and 6.

## 6. Discussion of Results

### (a) Oil recovery by water drive (Series 1)

The natural oil displacement characteristics of the Moonie core plugs were determined in these tests by waterflooding. The average recovery of the six wells showed 24.1 percent of oil in place at water-breakthrough, 39.8 percent at 97 percent water cut in the production stream and 50.5 percent at 99.8 percent water cut. This compares reasonably well with the current recovery in the southern portion of the field (42 percent of oil in place at 94 percent water cut).

Mobility ratios (MR) of all the floods average 0.94 indicating a reasonably good sweep efficiency. (Burcik (4) suggests an areal sweep efficiency of 72 percent in a reservoir if MR = 1). However, it is interesting to note that the more permeable samples generally show the highest mobility ratios in our tests, suggesting that some of the reduction in water mobility at primary depletion is probably due to minor particle movement/pore plugging in the "tighter core material". This characteristic may be less prevelant in the reservoir where dynamic conditions will have a reduced effect on flow in the individual smaller capillaries.

### (b) Oil Recovery by Polymerflooding (Series 1)

The initial polymerflood tests were carried out after samples were waterflooded in 6 (a), then cleaned, resaturated and again waterflooded followed by polymerflooding. As noted previously, the second waterfloods were adversely affected by changes in sample wettability, with rather poor oil recovery correlation between the two sets of waterflood tests (differences in recovery between the two basic runs averaged about 5 percent of oil in place).

Accordingly, polymer flooding could only be conducted after 100 percent water cuts had been established in the second "base" waterfloods. This averaged an additional 3.4 percent of oil recovery for 26 plugs (Table 4) with an average injection of 0.82 pore volumes of 500 ppm polymer. No meaningful polymer displacement characteristics could be evaluated at water cuts simulating current Moonie field conditions (94 percent water cut) because of the lack of suitable "base flood" results.

(c) <u>Residual Resistance Factors</u>

A measure of the effectiveness of polymer injection/retention may be determined by evaluating the displacing water mobility in reservoir rock before and after polymer injection; the ratio of the two displacing fluid permeabilities (i.e., before and after polymer) is the residual resistance $(\frac{Kw}{Kwp})$. This in turn indicates the "blocking action" of the polymer to following fluids in the reservoir thus indicating how diversion to and displacement in the lower permeability rock may occur. This is of vital importance because the greatest amount of residual oil is generally located in the lower permeability pore system.

These factors have been calculated for the polymer displacement in 6 (b) and are listed in Table 7. The samples have been tabulated according to their permeability to oil at residual water saturation and are listed in two groups - one group of 12 samples greater than 100 md and one group of 14 samples less than 100 md. For the high permeability samples, the residual resistance averaged 2.1 and for the low permeability group it averaged 3.5. The greater reduction of displacing fluid mobility in the "tighter" core material is a measure of the increased effectiveness of polymer film retention on the individual (smaller) pore spaces. However, this effect would be less prevelant in the reservoir where the main polymer flow would preferentially be through the more permeable channels (see manifold test results later in report).

(d) Polymer Adsorption and Degradation

During displacement tests with polymer, an attempt was made to evaluate the effect of mechanical degradation of the polymer due to shearing action of the porous media in the polymer solution. In addition, attempts were also made to measure the amount of polymer adsorption which occurred in the pore system. Both these factors are of significance in polymer displacement and control to a large extent the effectiveness of polymers within the formation in establishing and controlling lower water mobility.

Evaluation of these two factors in core samples is often conducted by determining the concentration of the polymer in the core effluent fluids using a turbidity meter and a capillary viscometer. However, the displacement volumes of polymer utilized in these tests were specifically tailored to determine additional oil recovery by polymer displacement; these volumes were generally insufficient to avoid dilution by water in front of and behind the polymer slug, thus interfering with quantitative interpretation of the results. Although some of the measured values of effluent polymer concentration are shown in Table 8, these results are inconclusive. Further work will be required in this field to specifically evaluate the effect of the Moonie pore system on polymers, using much greater volumes of polymer fluids.

It is doubtful however if mechanical or chemical degradation was a significant detrimental factor in these tests. This is based on the low (below shear) flow rates (5) used and also because of extensive use of noncontaminating glass/plastic receptacles for displacing fluids upstream of the core samples.

(e) Additional Polymer Tests (Series 2)

As noted, the wetting problems experienced with the initial set of core plugs, necessitated further testing, utilising a new group of samples. These were obtained from the Moonie reservoir from some of the same zones as previously studied. Two and three plug "sets" were selected from each interval to obviate any wetting problems. The basic properties of these samples are shown in Table 5.

The sequence of testing for these plugs was as follows. The samples were drilled, extracted, dried and subjected to routine porosity and permeability tests as previously. Each of the samples was then saturated with Moonie field water and irreducible water saturations were established by oil flushing as in 5(c) followed by measurement of permeability to oil.

Flooding tests were carried out on eight sets of adjacent plugs as follows. One plug from each set of eight samples was waterflooded to 100 percent water cut then four of the eight were subjected to polymer flooding (followed by waterflooding) using about $\frac{1}{3}$ of a pore volume slug of 500 ppm polymer. An adjacent plug from six of the sets was waterflooded to about 94 percent water cut, then polymer and waterflooded as described above. The balance of 4 plugs remaining from the sets were waterflooded to about 74 percent water cut (still containing mobile oil), then polymer and waterflooded to 100 percent water cut. The results of all these tests are shown in Table 6 and Figures 15 to 22 in which the polymer floods are directly compared to the basic water displacement tests.

The six basic waterflood tests showed average oil recoveries of 49.1 percent of oil in place at 100 percent water cut, comparing favourably with the basic tests described in VI(a). Four of the samples showed an additional 3.1 percent recovery by polymer flooding after basic flood tests at 100 percent water cut.

The six adjacent plugs polymer flooded after 94 percent water cut showed additional average oil recoveries of 4.9 percent over the basic flood tests, while the three plugs polymer flooded after 70 percent water cut showed an average oil recovery 7.1 percent greater than the basic waterflood tests at 100 percent water cut. Two of the plugs from the latter two groups of tests showed exceptionally high recoveries (14 percent of oil in place) after polymerflooding.

In nearly every case, the mobility ratios after polymer flooding (Table 6) are substantially lower than after the basic waterflood displacement tests (i.e. before polymer injection); this indicates significantly improved sweep efficiency. However, in some cases, the values appear inordinately low, possibly due to some permeability reduction due to particle dislodgement and plugging rather than from reduction due to the effects of polymer.

Residual resistance factors (FRr) again followed those determined in the Series 1 samples. These factors were characterized by low FRr for high permeability samples and high FRr for low permeability. This again suggests less reduction in flow capacity by polymers in the more permeable section of the reservoir.

It is interesting to note in these tests, the amount of oil recovered at a given displacing fluid throughout. Significantly, the samples having the most mobile oil always show the greatest recovery at a given throughput, in this case 2 pore volumes. Samples polymerflooded at a higher water cut showed lower oil recovery at the same water throughput (see Table 6).

This observation is in agreement with most of the literature on enhanced recovery which indicates that the amount of mobile oil present has a significant effect on recovery at any given displacement. The importance of a continuous oil phase remaining for as long as possible during displacement is obvious from these results.

(f) <u>Effective permeability to oil and water</u>

A further interesting effect from polymer injection was observed during additional testing (shown in Table 9). This involved measurement of both oil (Ko) and water (Kw) permeability before and after polymer injection as shown in the following sequential flow diagram.

| 1 | | 2 | | 3 | | 4 | |
|---|---|---|---|---|---|---|---|
| Establish residual water saturation by oil flushing | Ko → | Water flooding | Kw → | Polymer flooding | Kw → | Flush with oil to low water-oil ratios | Ko |

The final Ko was measured at very low water oil ratios (WOR = 0.02) and would symbolically represent the establishment of a new "bank" of displaced oil moving through the reservoir subsequent to and as a result of polymer injection. Actual reservoir conditions however would be characterized by somewhat higher water oil ratios.

The significant feature of these tests is that injected polymer, because of its affinity for water, markedly reduces the effective Kw, binding water by adsorption as a film to the reservoir pore walls. This apparently is not a reduction due to mechanical blockage since the effect on subsequent oil permeability is minimal (Kw reduction is 63%, Ko is 9%). This indicates another way in which polymers may promote oil production at the expense of water, and help to sustain continuity in the displaced oil bank.

(g) <u>Effect of Polymer Dilution by Water</u>

The prospect of some polymer dilution in the Moonie reservoir is probable through the active west-east trending edge water drive presently in existance. The quantity of dilution which might occur would be difficult to ascertain without field pilot studies; possibly polymer injection adjacent to the edge water influx on the western margin of the field may substantially restrict influx (and dilution).

In order to test the possible effects of dilution three adjacent samples were subjected to simultaneous injection of 500 ppm polymer and Moonie field water in equal amounts (0.3 pore volumes). This was initiated at

100 percent water cut in one sample and 95 and 91 percent water cut in the two adjacent samples. The three samples respectively showed recoveries of 32.8, 34.3 and 35.3 percent of oil in place (Figure 23).

Although additional confirmation of these tests through more extensive sampling and testing would be useful, the indications are that some dilution of the polymer can be tolerated without very substantial reductions in oil recovery.

(h) Manifold tests

In tests conducted so far in this study, the effects of polymer flow have only been determined in single plugs, representing a unit of reservoir with limited range in permeability. However, Moonie, as previously indicated is rather heterogeneous in nature with the reservoir being formed of a number of zones of widely varying permeability. The natural tendency in the reservoir is for edge water to preferentially flow through the most permeable layers, bypassing to some extent the lower permeability zones.

These individual zones are probably not laterally extensive in the reservoir, but the point remains that a considerable amount of oil is undoubtedly trapped in this fashion in this tighter material. Polymer solutions would be expected to reduce this preferential flow to some extent with reduction in flow in the high permeability zones, and redirection to the "tighter" high residual oil zones. The following manifold flow tests were conducted on two plug "sets" to evaluate this effect in the laboratory.

Three sets of samples were chosen for testing. Each "set" consisted of two plugs having a range of permeability which might comprise intermediate and high permeability reservoir characteristics. For example one two plug "set" showed permeability values of 104 and 825 md. Initially the (dry) samples were saturated with Moonie field water, then each was flushed to residual water saturation with oil and Ko was measured.

Subsequently, using a two Hassler-cell manifold, both plugs were simultaneously waterflooded using a common input until the permeable sample showed about 100 percent water cut; at this point the "tighter" sample in each manifold test showed water cuts of between 50 percent to 70 percent.

Polymer injection (500 ppm) was then commenced using an approximate input of 0.35 pore volumes in each reservoir "set"; this was followed by additional waterflooding.

Results of the tests, comprising water cuts, residual resistance factors, additional polymer oil recovery etc are shown in Table 10. The most significant feature of this data is the additional oil recovery subsequent to polymer injection; the low permeability side of each manifold set showed increased "polymer" oil recovery ranging from 12.8 percent to 20.9 percent of oil in place after polymer injection. It is interesting to note that this occurred with less than 0.1 pore volumes of polymer entering each of the low permeability samples, with the main stream continuing through the more permeable zones. Obviously, the main displacing mechanism is the water following polymer injection; this is further evidenced in the marked reduction in flow capacity to water in the high permeability samples and in their higher residual resistance factors obtained.

Certain aspects of these tests, notably the total recovery picture of the more permeable samples in each set appear lower than average, and it is felt that additional tests on this aspect using a broader range of samples need to be studied. Nevertheless, the tests do confirm that polymers are well suited to improved oil recovery in such stratified and heterogeneous type material, and could be expected to significantly improve oil recovery in certain of the tighter, poorly swept zones of the Moonie field, if severe dilution by the edge water drive is not a problem.

## 7. Conclusions

The injection of a 500 ppm polyacrylamide polymer into core plugs from the Moonie Reservoir having medium to high water cuts, has shown recovery of significant amounts of "polymer oil". Using polymer injection volumes of 0.25 to 2.5 pore volumes, polymer oil recovery varied from 0.8 percent of oil in place to 7.7 percent. Two samples showed recoveries over 14 percent, although this may have been a result of poor comparison between the test and control plug in a particular test suite or slightly lower water cuts.

Most of the samples showed marked reductions in water permeability and mobility ratios after polymer injection. Manifold tests involving simultaneous polymer flow through two samples showed a shift in flow from the high to low permeability plugs with significant improvement in oil recovery in the "tighter" material.

Although the tests showed that 0.05 percent and lower strength polymer produce significant amounts of "polymer oil", they fail to definitely establish whether polymer injected into the Moonie reservoir will be seriously effected by the edge water influx on the western margin of the field. This problem can only be answered by field pilot testing, which in any case may only be worthy of consideration if linear fluid movement in the reservoir is definitely established.

B A McKay — B.A. McKAY

Paul G Duff — P.G. DUFF

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TABLE 1

BASIC PROPERTIES - SERIES 1 SAMPLES

Well - MOONIE No. 4 | o/w contact - 5836

| Sample Number | Depth (feet) | Porosity (% bulk volume) | Permeability (millidarcys) Ka to dry nitrogen | Ko to oil at residual water saturation | Kw to water at residual oil saturation | Mobility ratio $\frac{Kw}{Uw} \div \frac{Uo}{Ko}$ | Residual water saturation before water flood (% pore vol.) | Lithology |
|---|---|---|---|---|---|---|---|---|
| 1 | 5806 | 20.1 | 1235 | 1189 | 619 | 1.05 | 33.0 | sst; f.gr. to m.gr; sl arg |
| 2 | 5807 | 17.3 | 678 | 648 | 416 | 1.28 | 42.5 | sst; m.gr. to v.c.gr. |
| 3 | 5808 | 19.1 | 228 | 160 | 57 | 0.71 | 41.8 | sst; m.gr. |
| 5 | 5817 | 20.0 | 140 | 97 | 36 | 1.26 | 42.3 | sst; f.gr. to m.gr. |
| 6 | 5820 | 19.3 | 87 | 32 | 7.7 | 0.48 | 55.4 | sst; f.gr., arg. |
| 7 | 5824 | 20.0 | 1136 | 967 | 672 | 1.39 | 41.4 | sst; m.gr. to c.gr. |
| 8 | 5827 | 16.1 | 16 | 4.0 | 1.6 | 0.80 | 66.7 | sst; f.gr. to c.gr. |
| 9 | 5829 | 19.2 | 428 | 221 | 66 | 0.59 | 56.8 | sst; m.gr. to v.c.gr. |
| 10 | 5830 | 16.5 | 97 | 24 | 7.9 | 0.66 | 68.3 | sst; m.gr. to c.gr. |
| 11 | 5832 | 19.1 | 738 | 398 | 54 | 0.27 | 64.3 | sst; m.gr. to v.c.gr. |
| Average | | 17.6 | 478 | 374 | 194 | 0.85 | 51.2 | - |

TABLE 1 (cont)

Well - MOONIE No. 9 o/w contact - 5833

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 13 | 5812 | 16.0 | 22 | 3.9 | 2.3 | 1.17 | 66.9 | sst; f.gr. to v.c.gr. |
| 14 | 5817 | 14.9 | 16 | 5.1 | 2.4 | 0.94 | 67.4 | sst; f.gr. to m.gr. |
| 15 | 5831 | 17.7 | 881 | 722 | 248 | 0.68 | 68.9 | sst; m.gr. to v.c.gr., arg. |
| Average | | 16.2 | 306 | 244 | 84 | 0.93 | 67.7 | - |

Well - MOONIE No. 13 o/w contact - 5842

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 19 | 5821 | 19.4 | 91 | 28 | 14 | 1.00 | 53.5 | sst; m.gr. to c.gr., arg. |
| 20 | 5823 | 17.2 | 341 | 281 | 124 | 0.88 | 46.7 | as above |
| 21 | 5826 | 17.5 | 347 | 136 | 63 | 0.92 | 57.3 | as above |
| 22 | 5830 | 16.7 | 70 | 22 | 8.6 | 0.78 | 53.9 | sst; m.gr. to c.gr. |
| Average | | 17.7 | 212 | 116 | 56 | 0.89 | 52.8 | - |

TABLE 1 (cont)

Well - MOONIE No. 26

o/w contact - 5824

| Sample Number | Depth (feet) | Porosity (% bulk volume) | Permeability (millidarcys) Ka to dry nitrogen | Ko to oil at residual water saturation | Kw to water at residual oil saturation | Mobility ratio $\frac{Kw}{Uw} \cdot \frac{Uo}{Ko}$ | Residual water saturation before water flood (% pore vol.) | Lithology |
|---|---|---|---|---|---|---|---|---|
| 24 | 5768 | 19.7 | 148 | 65 | 29 | 0.89 | 43.4 | sst; f.gr. to v.c.gr., arg. |
| 25 | 5771 | 19.1 | 90 | 44 | 19 | 0.86 | 46.1 | |
| 26 | 5773 | 15.4 | 106 | 54 | 22 | 0.81 | 46.1 | sst; m.gr. to v.c.gr. |
| 27 | 5776 | 19.1 | 488 | 408 | 31 | * | 38.2 | sst; m.gr. to c.gr., sl.arg |
| 28 | 5780 | 18.3 | 205 | 149 | 43 | 0.58 | 43.2 | as above |
| 29 | 5782 | 20.5 | 1279 | 1299 | 1196 | 1.34 | 35.4 | sst; m.gr. to c.gr. |
| 30 | 5785 | 20.5 | 1751 | 1380 | 583 | 0.84 | 37.9 | as above |
| 31 | 5788 | 19.9 | 1234 | 999 | 778 | 1.55 | 33.6 | as above |
| 32 | 5790 | 19.7 | 249 | 188 | 66 | 0.70 | 42.9 | as above |
| 33 | 5792 | 16.7 | 75 | 47 | 16 | 0.68 | 42.9 | sst; m.gr. |
| 34 | 5799 | 13.3 | 19 | 9.0 | 2.0 | 0.44 | 62.8 | sst; f.gr. to m.gr., sl. carb |
| 35 | 5801 | 18.1 | 588 | 472 | 302 | 1.28 | 41.8 | sst; m.gr. to c.gr. |
| 36 | 5803 | 14.3 | 65 | 24 | 14 | 1.16 | 54.6 | sst; m.gr. to v.c.gr. |
| 37 | 5804 | 14.7 | 70 | 34 | 16 | 0.94 | 57.1 | sst; m.gr. to c.gr. sl. calc. |
| 38 | 5819 | 18.8 | 164 | 50 | 16 | 0.64 | 66.9 | sst; m.gr. sl. arg. |
| Average | | 17.9 | 433 | 348 | 209 | 0.94* | 46.2 | - |

Well - MOONIE No. 27 o/w contact 5840

| Sample Number | Depth (feet) | Porosity (% bulk volume) | Permeability (millidarcys) Ka to dry nitrogen | Ko to oil at residual water saturation | Kw to water at residual oil saturation | Mobility ratio $\frac{Kw}{Uw} \cdot \frac{Uo}{Ko}$ | Residual water saturation before water flood (% pore vol.) | Lithology |
|---|---|---|---|---|---|---|---|---|
| 41 | 5772 | 15.8 | 35 | 15 | 6.9 | 0.92 | 50.5 | sst; m.gr. |
| 42 | 5775 | 14.4 | 39 | 20 | 9.4 | 0.94 | 48.8 | sst; m.gr. to v.c.gr., sl. carb |
| 43 | 5778 | 18.3 | 103 | 69 | 29 | 0.84 | 44.4 | sst; m.gr. to c.gr. |
| 44 | 5781 | 17.9 | 1412 | 1248 | 919 | 1.47 | 38.7 | sst; c.gr. to v.c.gr. |
| 45 | 5782 | 18.3 | 96 | 58 | 26 | 0.89 | 44.5 | sst; c.gr. |
| 46 | 5784 | 15.6 | 14 | 6.3 | 3.3 | 1.04 | 52.9 | sst; m.gr. to c.gr. |
| 47 | 5787 | 15.0 | 10 | 4.4 | 2.0 | 0.90 | 53.1 | sst; f.gr. to m.gr. |
| 48 | 5788 | 20.1 | 1489 | 1291 | 773 | 1.19 | 36.7 | sst; c.gr. to v.c.gr. |
| 49 | 5789 | 13.4 | 11 | 4.1 | 2.3 | 1.09 | 57.6 | sst; m.gr to v. gr. sl. arg and carb. |
| 50 | 5791 | 17.1 | 329 | 251 | 119 | 0.95 | 42.0 | sst; m.gr. to c.gr. sl. arg |
| 51 | 5793 | 19.7 | 704 | 624 | 226 | 0.72 | 36.7 | sst; c.gr. |
| 52 | 5795 | 18.9 | 1339 | 1368 | 1279 | 1.86 | 34.9 | sst; c.gr. to v.c. gr. |
| 53 | 5802 | 12.4 | 3.5 | 1.3 | 0.16 | * | 68.5 | sst; f.gr. slty |
| 54 | 5806 | 18.7 | 499 | 426 | 153 | 0.72 | 44.1 | sst; m.gr. |
| 55 | 5808 | 13.5 | 32 | 26 | 9.0 | 0.69 | 57.0 | sst; c.gr. to v.c.gr. |

TABLE 1 (cont)

Well - MOONIE No. 27 (cont)

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 56 | 5810 | 19.0 | 476 | 427 | 208 | 0.97 | 44.9 | sst; m.gr. to c.gr. |
| 57 | 5812 | 16.3 | 1032 | 1231 | 619 | 1.00 | 47.6 | sst; c.gr. to v.c.gr. |
| 58 | 5813 | 13.8 | 133 | 77 | 33 | 0.86 | 53.5 | sst; c.gr. to v.c.gr., arg. |
| 59 | 5816 | 18.6 | 142 | 81 | 25 | 0.62 | 54.3 | sst; m.gr. |
| 60 | 5818 | 17.0 | 247 | 140 | 48 | 0.68 | 53.4 | sst; m.gr to c.gr. |
| 61 | 5822 | 16.2 | 44 | 15 | 6.6 | 0.88 | 64.2 | sst; m.gr |
| 62 | 5830 | 16.4 | 135 | 38 | 15 | 0.78 | 68.7 | sst; m.gr to c.gr. |
| Average | | 16.6 | 378 | 337 | 205 | 0.95* | 49.8 | - |

*Result not available for No. 53

TABLE 1 (cont)

Well - MOONIE No. 34 — o/w contact 5842

| Sample Number | Depth (feet) | Porosity (% bulk volume) | Permeability (millidarcys) Ka to dry nitrogen | Ko to oil at residual water saturation | Kw to water at residual oil saturation | Mobility ratio $\frac{K_w}{U_w} \cdot \frac{U_o}{K_o}$ | residual water saturation before water flood (% pore vol.) | Lithology |
|---|---|---|---|---|---|---|---|---|
| 63 | 5776 | 19.0 | 49 | 20 | 13 | 1.3 | 51.0 | sst; m.gr. sl. arg. |
| 64 | 5785 | 17.3 | 96 | 42 | 22 | 1.05 | 46.6 | sst; m.gr. to v.c.gr sl.arg |
| 65 | 5801 | 16.3 | 302 | 207 | 86 | 0.85 | 43.2 | sst; m.gr. to c.gr. |
| 66 | 5803 | 19.9 | 4647 | 3074 | 3000 | 1.95 | 25.8 | sst; m.gr. to v.c.gr |
| 67 | 5805 | 16.5 | 49 | 23 | 5.2 | 0.45 | 56.1 | sst; f.gr. |
| 68 | 5807 | 18.3 | 595 | 563 | 199 | 0.71 | 37.8 | sst; m.gr. |
| 69 | 5809 | 20.2 | 1749 | 1684 | 1506 | 1.79 | 29.5 | sst; m.gr. to c.gr. |
| 70 | 5811 | 18.7 | 2375 | 2283 | 1940 | 1.70 | 33.7 | sst; c.gr. to v.c.gr. sl. calc |
| 71 | 5814 | 18.8 | 264 | 188 | 70 | 0.74 | 43.5 | sst; m.gr. to c.gr. |
| 72 | 5816 | 15.4 | 576 | 520 | 494 | 1.90 | 50.4 | sst; m.gr. to v.c.gr. |
| 73 | 5818 | 16.9 | 224 | 75 | 39 | 1.04 | 54.4 | sst; m.gr. to c.gr., sl.arg. |
| 74 | 5823 | 16.7 | 23 | 6.7 | 1.6 | 0.42 | 67.2 | sst; f.gr to m. |
| 75 | 5828 | 16.4 | 342 | 294 | 83 | 0.56 | 52.1 | sst; m.gr. to arg. |
| 76 | 5829 | 18.8 | 1293 | 1053 | 482 | 0.83 | 46.1 | as above |
| Average | | 17.8 | 902 | 652 | 567 | 1.09 | 45.5 | |

TABLE 2

WATER ANALYSIS - MOONIE OIL FIELD

| | |
|---|---|
| Sample depth (metres) | 1780 (approx) |
| Sodium (Na) | 730 ppm |
| Potassium (K) | 24 " |
| Calcium (Ca) | 5 " |
| Magnesium (Mg) | 2 " |
| Chloride (Cl) | 174 " |
| Sulphate ($SO_4$) | 6 " |
| Bicarbonate ($HCO_3$) | 1615 " |
| Fluoride (F) | 3.3 " |
| Nitrate ($NO_3$) | 8 " |
| Total dissolved solids | 1823 " |
| Hardness as $CaCO_3$ | 21 " |
| Alkalinity as $CaCO_3$ | 1452 " |
| Carbonate ($CO_3$) | 77 " |
| pH | 8.7 |

# TABLE 3

## OIL RECOVERY BY WATERFLOODING - SERIES 1 SAMPLES

Well MOONIE - 4

Displacing water - Moonie Field water
Producing water/oil viscosity ratio - 0.47
Oil/water contact - 5836'

| Sample Number | Depth (feet) | OIL RECOVERY % pore volume | | | | | OIL RECOVERY % hydrocarbon volume | | | | | Water Cut % total production | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | 1 PV | 2 PV | 5 PV | 10 PV |
| 1 | 5806 | 20.7 | 31.6 | 35.0 | 38.7 | 41.7 | 31.0 | 47.1 | 52.2 | 57.7 | 62.2 | 95.0 | 98.0 | 99.4 | 99.6 |
| 2 | 5807 | 15.6 | 22.4 | 24.5 | 27.3 | 29.5 | 27.2 | 33.4 | 36.5 | 40.7 | 44.0 | 98.0 | 99.0 | 99.3 | 99.5 |
| 3 | 5808 | 13.2 | 28.2 | 31.0 | 34.0 | 36.1 | 22.7 | 48.4 | 53.2 | 58.4 | 62.0 | 96.8 | 98.4 | 99.3 | 99.7 |
| 5 | 5817 | 9.6 | 25.0 | 28.7 | 31.8 | 33.8 | 16.6 | 43.3 | 49.7 | 55.1 | 58.6 | 96.0 | 98.2 | 99.1 | 99.6 |
| 6 | 5820 | 14.9 | 19.0 | 19.5 | 20.2 | 20.7 | 33.4 | 42.6 | 43.7 | 45.3 | 46.4 | 99.0 | 99.5 | 99.6 | 100 |
| 7 | 5824 | 11.0 | 18.6 | 22.0 | 25.6 | 27.4 | 18.8 | 31.7 | 37.5 | 43.7 | 46.7 | 94.8 | 98.0 | 99.3 | 99.6 |
| 8 | 5829 | 8.4 | 14.4 | 15.8 | 16.1 | 16.1 | 25.2 | 43.2 | 47.4 | 48.3 | 48.3 | 98.6 | 99.2 | 100 | 100 |
| 9 | 5829 | 8.6 | 16.0 | 17.2 | 17.8 | 18.2 | 19.9 | 37.0 | 39.8 | 41.2 | 42.1 | 97.5 | 99.5 | 99.8 | 100 |
| 10 | 5830 | 4.6 | 11.1 | 11.4 | 11.4 | - | 14.5 | 35.0 | 36.0 | 36.0 | - | 99.0 | 99.6 | 100 | - |
| 11 | 5832 | 12.1 | 18.9 | 19.7 | 20.2 | 20.4 | 33.9 | 52.9 | 55.2 | 56.6 | 57.1 | 98.0 | 99.5 | 99.5 | 99.8 |
| Average | | 11.8 | 20.5 | 22.4 | 24.3 | 25.5 | 24.3 | 41.4 | 45.1 | 48.3 | 50.3 | 97.2 | 98.9 | 99.5 | 99.8 |

Well MOONIE - 9

Oil/Water contact - 5833'

| Sample Number | Depth (feet) | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | 1 PV | 2 PV | 5 PV | 10 PV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | 5812 | 7.7 | 13.1 | 14.7 | 15.8 | 15.8 | 23.3 | 39.6 | 44.4 | 47.7 | 47.7 | 99.0 | 99.4 | 99.9 | 100 |
| 14 | 5817 | 7.8 | 14.9 | 15.6 | 16.2 | 16.9 | 23.9 | 45.7 | 47.8 | 49.7 | 51.8 | 99.0 | 99.3 | 99.6 | 99.9 |
| 15 | 5831 | 7.8 | 10.5 | 11.0 | 11.6 | 12.0 | 25.0 | 33.7 | 35.4 | 37.3 | 38.6 | 99.0 | 99.4 | 99.6 | 99.9 |
| Average | | 7.8 | 12.8 | 13.8 | 14.5 | 44.7 | 24.0 | 39.6 | 42.5 | 44.9 | 46.0 | 99.0 | 99.4 | 99.7 | 99.9 |

TABLE 3 (cont)

Well NOONIE - 13 Oil/Water contact - 5842'

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19 | 5821 | 7.7 | 12.5 | 14.7 | 21.0 | 23.3 | 16.5 | 26.9 | 31.6 | 45.2 | 50.1 | 96.0 | 97.7 | 99.3 | 99.6 |
| 20 | 5823 | 11.6 | 18.6 | 23.0 | 26.7 | 29.2 | 21.7 | 34.9 | 43.1 | 50.1 | 54.8 | 96.0 | 98.5 | 99.5 | 99.6 |
| 21 | 5826 | 8.8 | 14.0 | 15.9 | 16.9 | 17.0 | 20.6 | 32.8 | 37.2 | 39.6 | 39.8 | 98.0 | 99.1 | 99.8 | 99.9 |
| 22 | 5830 | 15.4 | 21.8 | 23.3 | 24.2 | 24.8 | 33.4 | 47.3 | 50.5 | 52.5 | 53.7 | 97.6 | 99.0 | 99.8 | 99.9 |
| Average | | 10.9 | 16.7 | 19.2 | 22.2 | 23.6 | 23.0 | 35.5 | 40.6 | 46.8 | 49.6 | 96.9 | 98.6 | 99.6 | 99.8 |

TABLE 3 (cont)

Well - MOONIE 26

Displacing water - Moonie Field water
Producing water/oil vicsocity - 0.47
Oil/Water contact - 5824'

| Sample Number | Depth (feet) | OIL RECOVERY % pore volume | | | | | % hydrocarbon volume | | | | | Water Cut % total production | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | 1 PV | 2 PV | 5 PV | 10 PV |
| 24 | 5768 | 13.9 | 28.6 | 31.0 | 34.0 | 35.8 | 24.5 | 50.5 | 54.8 | 60.1 | 63.2 | 97.0 | 98.5 | 99.5 | 99.8 |
| 25 | 5771 | 14.4 | 25.8 | 28.5 | 31.0 | 32.7 | 26.7 | 47.8 | 52.8 | 57.5 | 60.6 | 96.0 | 98.5 | 99.5 | 99.8 |
| 26 | 5773 | 7.2 | 15.0 | 19.2 | 22.5 | 24.1 | 13.3 | 27.8 | 35.6 | 41.7 | 44.7 | 96.0 | 98.5 | 99.2 | 99.7 |
| 27 | 5776 | 9.7 | 21.0 | 24.2 | 28.1 | 31.7 | 15.7 | 34.0 | 39.1 | 45.4 | 51.2 | 94.0 | 97.5 | 99.0 | 99.5 |
| 28 | 5780 | 11.1 | 20.0 | 21.8 | 24.5 | 27.4 | 19.5 | 35.2 | 36.4 | 43.1 | 48.2 | 96.5 | 98.5 | 99.2 | 99.6 |
| 29 | 5782 | 7.5 | 18.3 | 20.8 | 24.0 | 27.9 | 11.6 | 28.3 | 32.2 | 37.1 | 43.2 | 97.5 | 98.8 | 99.4 | 99.6 |
| 30 | 5785 | 14.9 | 30.5 | 34.0 | 38.5 | 40.6 | 23.9 | 49.1 | 54.7 | 61.9 | 65.2 | 95.0 | 98.0 | 99.4 | 99.6 |
| 31 | 5788 | 18.9 | 29.5 | 32.7 | 36.8 | 39.5 | 28.4 | 44.4 | 49.2 | 55.4 | 59.5 | 95.0 | 98.0 | 99.2 | 99.5 |
| 32 | 5790 | 8.2 | 20.0 | 22.0 | 24.8 | 27.3 | 14.3 | 35.0 | 38.5 | 43.4 | 47.8 | 96.5 | 98.6 | 99.1 | 99.6 |
| 33 | 5792 | 15.2 | 22.5 | 25.5 | 28.1 | 30.7 | 26.6 | 39.4 | 44.6 | 49.2 | 53.7 | 96.0 | 98.1 | 99.0 | 99.6 |
| 34 | 5799 | 9.9 | 14.5 | 15.3 | 16.5 | 17.4 | 26.6 | 38.9 | 41.1 | 44.3 | 46.7 | 98.8 | 99.2 | 99.4 | 99.7 |
| 35 | 5801 | 11.1 | 20.0 | 22.5 | 26.8 | 29.5 | 19.1 | 34.3 | 38.6 | 46.0 | 50.7 | 96.5 | 98.0 | 98.8 | 99.5 |
| 36 | 5803 | 8.5 | 17.9 | 19.9 | 21.8 | 22.8 | 18.7 | 39.4 | 43.8 | 48.0 | 50.2 | 97.0 | 98.5 | 99.5 | 99.8 |
| 37 | 5804 | 12.3 | 14.6 | 15.1 | 15.9 | 16.0 | 28.7 | 34.0 | 35.2 | 53.2 | 37.3 | 99.0 | 99.5 | 99.8 | 99.9 |
| 38 | 5819 | 5.3 | 7.1 | 8.5 | 8.5 | 8.5 | 16.0 | 21.4 | 25.7 | 25.7 | 25.7 | 98.6 | 99.4 | 100 | 100 |
| Average | | 11.2 | 20.3 | 22.7 | 26.9 | 27.4 | 20.9 | 37.3 | 41.6 | 47.4 | 49.8 | 96.6 | 98.5 | 99.3 | 99.7 |

Well - MOONIE 27

Displacing water - Moonie Field water
Producing water/oil viscosity ratio - 0.47
Oil/water contact - 5840'

| Sample Number | Depth (feet) | OIL RECOVERY | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | % pore volume | | | | | % hydrocarbon volume | | | | | Water cut % total production | | | |
| | | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | 1 PV | 2 PV | 5 PV | 10 PV |
| 41 | 5772 | 12.8 | 22.4 | 25.0 | 27.2 | 28.8 | 25.8 | 43.2 | 50.5 | 54.9 | 58.2 | 97.0 | 98.7 | 99.5 | 99.7 |
| 42 | 5775 | 10.4 | 23.5 | 26.0 | 28.8 | 31.0 | 20.3 | 45.9 | 50.8 | 56.2 | 60.5 | 96.0 | 98.0 | 99.3 | 99.6 |
| 43 | 5778 | 11.4 | 25.9 | 29.2 | 33.2 | 35.8 | 20.5 | 46.6 | 52.5 | 59.7 | 64.4 | 93.5 | 97.8 | 99.3 | 99.7 |
| 44 | 5781 | 17.10 | 27.0 | 29.5 | 32.2 | 33.9 | 27.9 | 44.0 | 48.1 | 52.5 | 55.3 | 96.0 | 98.3 | 99.2 | 99.7 |
| 45 | 5782 | 15.0 | 27.9 | 30.9 | 33.3 | 35.2 | 27.0 | 50.3 | 55.6 | 59.9 | 63.4 | 94.2 | 97.8 | 99.2 | 99.7 |
| 46 | 5784 | 13.5 | 24.0 | 26.9 | 28.7 | 30.0 | 28.7 | 50.9 | 57.1 | 60.9 | 63.6 | 96.2 | 98.3 | 99.3 | 99.8 |
| 47 | 5787 | 18.1 | 28.0 | 29.8 | 31.9 | 32.9 | 38.6 | 59.7 | 63.5 | 68.0 | 70.1 | 97.0 | 98.6 | 99.5 | 99.8 |
| 48 | 5788 | 20.1 | 26.4 | 28.5 | 32.0 | 33.5 | 31.7 | 41.7 | 45.0 | 50.5 | 52.9 | 97.6 | 98.4 | 99.3 | 99.8 |
| 49 | 5789 | 7.9 | 15.4 | 18.5 | 20.7 | 21.4 | 18.6 | 36.2 | 43.5 | 48.7 | 50.3 | 98.0 | 99.0 | 99.4 | 99.7 |
| 50 | 5791 | 13.3 | 22.1 | 24.8 | 27.9 | 29.5 | 22.9 | 38.1 | 42.7 | 48.1 | 50.8 | 97.0 | 98.0 | 99.3 | 99.7 |
| 51 | 5793 | 13.7 | 23.5 | 25.0 | 27.2 | 28.8 | 21.6 | 37.1 | 39.5 | 42.9 | 45.5 | 97.5 | 98.5 | 99.4 | 99.7 |
| 52 | 5795 | 14.9 | 23.0 | 27.0 | 30.5 | 34.0 | 22.9 | 35.3 | 41.5 | 46.8 | 52.2 | 96.0 | 98.0 | 99.0 | 99.6 |
| 53 | 5802 | 9.0 | 12.5 | 13.1 | 13.5 | 13.5 | 28.5 | 39.6 | 41.6 | 42.8 | 42.8 | 99.0 | 99.5 | 100 | 100 |
| 54 | 5806 | 19.6 | 29.5 | 32.2 | 33.9 | 34.9 | 35.1 | 52.8 | 57.6 | 60.6 | 62.4 | 96.5 | 99.0 | 99.4 | 99.8 |
| 55 | 5808 | 8.0 | 16.9 | 19.1 | 21.5 | 22.6 | 16.6 | 39.3 | 44.4 | 50.0 | 52.5 | 96.6 | 98.5 | 99.3 | 99.8 |

Well - MOONIE 27 (cont)

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 56 | 5810 | 11.3 | 26.0 | 29.7 | 33.0 | 36.0 | 20.5 | 47.2 | 53.9 | 59.9 | 65.3 | 94.0 | 97.6 | 99.2 | 99.6 |
| 57 | 5812 | 9.6 | 16.0 | 18.0 | 21.2 | 23.1 | 18.3 | 30.5 | 34.3 | 40.4 | 44.1 | 96.0 | 98.0 | 99.6 | 99.8 |
| 58 | 5813 | 12.1 | 20.8 | 23.1 | 25.5 | 26.9 | 26.0 | 44.7 | 49.7 | 54.8 | 57.8 | 97.0 | 98.8 | 99.2 | 99.7 |
| 59 | 5816 | 11.7 | 18.8 | 20.8 | 22.0 | 22.4 | 56.0 | 41.1 | 45.5 | 48.1 | 49.0 | 97.8 | 99.5 | 99.7 | 99.9 |
| 60 | 5818 | 12.6 | 21.6 | 23.6 | 25.2 | 25.5 | 27.1 | 46.4 | 50.7 | 54.2 | 54.8 | 97.8 | 98.6 | 99.8 | 99.9 |
| 61 | 5822 | 7.7 | 13.1 | 13.5 | 13.6 | 15.0 | 21.5 | 36.6 | 37.7 | 38.0 | 41.9 | 98.9 | 99.0 | 99.6 | 99.9 |
| 62 | 5830 | 8.6 | 13.2 | 15.6 | 16.7 | 17.0 | 27.4 | 42.2 | 49.8 | 53.3 | 54.3 | 97.0 | 98.9 | 99.6 | 99.9 |
| Average | | 12.6 | 21.7 | 24.1 | 26.3 | 27.8 | 26.6 | 43.2 | 47.9 | 52.3 | 55.1 | 96.6 | 98.5 | 99.4 | 99.8 |

TABLE 3 (cont)

Well - MOONIE 34

Displacing water - Moonie field water
Producing water/oil viscosity ratio - 0.47
Oil/water contract - 5842'

| Sample Number | Depth (feet) | OIL RECOVERY % pore volume | | | | | % hydrocarbon volume | | | | | Water Cut % total production | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | B.T. | 1 PV | 2 PV | 5 PV | 10 PV | 1 PV | 2 PV | 5 PV | 10 PV |
| 63 | 5776 | 10.0 | 24.0 | 27.4 | 29.9 | 31.9 | 20.4 | 44.4 | 55.9 | 61.0 | 65.1 | 95.5 | 98.2 | 99.3 | 99.6 |
| 64 | 5785 | 10.8 | 23.3 | 26.7 | 30.5 | 32.8 | 20.2 | 43.6 | 50.0 | 57.1 | 61.4 | 95.0 | 97.8 | 99.2 | 99.7 |
| 65 | 5801 | 13.4 | 18.5 | 21.0 | 24.0 | 26.0 | 23.6 | 32.6 | 36.9 | 42.2 | 45.8 | 96.0 | 98.4 | 99.3 | 99.7 |
| 66 | 5803 | 20.2 | 33.2 | 39.0 | 43.7 | 46.0 | 27.2 | 44.7 | 52.5 | 58.9 | 61.9 | 92.0 | 97.7 | 99.3 | 99.5 |
| 67 | 5805 | 14.0 | 18.0 | 19.0 | 20.0 | 20.8 | 31.8 | 41.0 | 43.3 | 45.5 | 47.4 | 98.8 | 99.3 | 99.6 | 99.9 |
| 68 | 5807 | 20.9 | 29.7 | 31.5 | 34.0 | 35.6 | 33.6 | 47.7 | 50.6 | 54.7 | 57.2 | 97.0 | 98.0 | 99.0 | 99.7 |
| 69 | 5809 | 28.7 | 37.0 | 41.0 | 44.2 | 47.0 | 40.7 | 52.5 | 58.1 | 62.7 | 66.7 | 94.0 | 98.2 | 99.1 | 99.5 |
| 70 | 5811 | 10.8 | 22.8 | 27.0 | 31.8 | 36.0 | 16.3 | 34.4 | 40.7 | 47.9 | 54.3 | 94.0 | 97.2 | 99.0 | 99.5 |
| 71 | 5814 | 17.3 | 24.0 | 26.0 | 28.6 | 30.0 | 30.6 | 42.5 | 46.0 | 50.6 | 53.1 | 97.0 | 98.0 | 99.2 | 99.8 |
| 72 | 5816 | 6.7 | 12.5 | 15.2 | 19.1 | 21.2 | 13.5 | 25.2 | 30.6 | 38.5 | 42.7 | 96.0 | 98.0 | 99.2 | 99.6 |
| 73 | 5818 | 11.0 | 17.4 | 19.0 | 20.8 | 21.5 | 24.1 | 38.1 | 41.7 | 45.6 | 47.1 | 98.0 | 98.8 | 99.5 | 99.9 |
| 74 | 5823 | 10.1 | 13.8 | 14.1 | 14.5 | 14.6 | 30.7 | 42.1 | 43.0 | 44.2 | 44.5 | 99.5 | 99.6 | 99.9 | 99.9 |
| 75 | 5828 | 8.3 | 16.5 | 18.0 | 20.1 | 22.0 | 17.3 | 34.4 | 37.6 | 41.9 | 45.9 | 98.0 | 98.5 | 99.5 | 99.8 |
| 76 | 5829 | 9.2 | 16.5 | 19.4 | 21.9 | 23.8 | 17.1 | 34.3 | 36.0 | 40.6 | 44.1 | 98.0 | 98.6 | 99.4 | 99.8 |
| Average | | 13.6 | 22.1 | 24.6 | 27.4 | 29.2 | 24.8 | 39.8 | 44.5 | 49.4 | 52.6 | 96.3 | 98.3 | 99.3 | 99.7 |

Table 4

OIL RECOVERED BY POLYMER INJECTION - SERIES 1 SAMPLES

| Sample Number | Polymer injected at 100% water cut (pore volumes) | Oil produced after polymer injection (% oil in place) |
|---|---|---|
| 6 | 0.54 | 1.8 |
| 10 | 0.95 | 3.1 |
| 14 | 0.66 | 6.2 |
| 15 | 0.75 | 0.6 |
| 22 | 0.59 | 6.2 |
| 26 | 0.79 | 6.1 |
| 27 | 0.88 | 7.4 |
| 31 | 0.69 | 2.4 |
| 32 | 0.74 | 2.8 |
| 33 | 0.93 | 1.9 |
| 35 | 2.17 | 5.7 |
| 36 | 0.75 | 1.3 |
| 37 | 0.63 | 2.3 |
| 39 | 0.28 | 2.1 |
| 42 | 0.97 | 6.4 |
| 43 | 0.59 | 2.1 |
| 50 | 1.50 | 5.1 |
| 51 | 0.60 | 1.5 |
| 58 | 0.48 | 5.8 |
| 60 | 1.45 | 5.4 |
| 67 | 0.66 | 0.9 |
| 69 | 0.77 | 0.8 |
| 70 | 0.61 | 2.9 |
| 72 | 0.78 | 2.4 |
| 73 | 0.78 | 4.3 |
| 75 | 0.67 | 1.4 |
| Average | 0.82 | 3.4 |

Table 5

BASIC PROPERTIES - SERIES 2 SAMPLES

| Well | Sample Number | Depth (feet) | Porosity (% bulk volume) | Permeability (Md.) to dry nitrogen | Permeability (Md.) to oil at residual water saturation | Permeability (Md.) to water at residual oil saturation | Mobility ratio $\frac{K_w}{U_w} \cdot \frac{U_o}{K_o}$ | Residual water saturation before water flood (% P.V.) | Lithology |
|---|---|---|---|---|---|---|---|---|---|
| 4 | A | 5806'7" | 20.8 | 1177 | sample used for other tests - see Figure 23 | | | | |
| 4 | B | 5808'0" | 10.4 | 0.3 | no further testing - permeability too low | | | | |
| 26 | C | 5768'5" | 16.5 | 2.5 | no further testing - permeability too low | | | | |
| 26 | D | 5771'10" | 19.1 | 86 | 29 | 10 | 0.69 | 46.0 | sst; m.gr. to v.c.gr. |
| 26 | E | 5780'0" | 15.7 | 21 | 3.1 | 2.1 | 1.35 | 45.0 | sst; m.gr. to c.gr. sl. arg. |
| 26 | F | 5790'0" | 21.4 | 439 | 268 | 66 | 0.49 | 49.0 | sst; m.gr. to c.gr. |
| 27 | G | 5778'4" | 19.0 | 97 | 70 | 7.1 | 0.21 | 47.0 | sst; m.gr. to c.gr. |
| 27 | H | 5781'3" | 8.8 | 0.1 | no further testing - permeability too low | | | | |

TABLE 5 (cont)

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 27 | I | 5805'9" | 19.5 | 357 | Sample used for other tests - see Table 10 | | | | |
| 27 | J | 5809'11" | 16.9 | 175 | Sample used for other tests - see Table 10 | | | | |
| 34 | K | 5800'11" | 18.5 | 1129 | 1100 | 713 | 1.30 | 51.0 | sst; m.gr. to c.gr. |
| 34 | L-I | 5802'10" | 22.6 | 1856 | 1790 | 668 | 0.75 | 40.0 | sst; m.gr. to v.c.gr. |
| 34 | M-I | 5807'0" | 20.4 | 330 | 168 | 34 | 0.40 | 44.0 | sst; m.gr. |
| 34 | N | 5809'6" | 23.7 | 1813 | 1811 | 821 | 0.90 | 40.0 | sst; m.gr. to c.gr. |

TABLE 6

Recovery characteristics by waterflooding and polymer displacement
Moonie Field - Series 2 samples

| Well | Sample Number | Depth (feet) | Permeability to oil at residual water saturation (before polymer) (Md.) | Amount of polymer injected P.V. | Effluent water cut at polymer injection (%) | Total oil recovery at 100% water cut % H.C.V. | Additional oil produced by polymer injection % H.C.V. | Oil recovery at 2 PV throughput % H.C.V. | Residual resistance factors $\frac{\text{Kw before pol.}}{\text{Kw after pol.}}$ | Mobility ratios $\frac{Kw}{Uw} \cdot \frac{Uo}{Ko}$ |
|---|---|---|---|---|---|---|---|---|---|---|
| 26 | D | 5771'10" | 29 | - | - | 49.7 | - | 40.0 | - | 0.69 |
| 26 | D-3 | 5771'10" | 32 | 0.29 | 97 | 52.9 | 3.2 | 45.0 | 5.5 | 0.06 |
| 26 | D-1 | 5771'10" | 20 | 0.36 | 68 | 55.2 | 5.5 | 49.0 | 3.1 | 0.15 |
| 26 | E | 5780'0" | 3.1 | - | - | 49.6 | - | 45.0 | - | 1.35 |
| 26 | E | | 3.1 | 0.47 | 99 | 57.3 | 7.7 | - | 4.2 | 0.32 |
| 26 | E-1 | | 2.7 | 0.42 | 86 | 63.6 | 14.0 | 58.0 | 2.4 | 0.52 |
| 26 | F | 5790'0" | 268 | - | - | 42.6 | - | 33.0 | - | 0.49 |
| 26 | F-3 | | 364 | 0.25 | 97 | 44.7 | 2.1 | 38.0 | 1.3 | 0.12 |
| 26 | F-1 | | 260 | 0.30 | 72 | 46.9 | 4.3 | 41.0 | 2.3 | 0.16 |
| 27 | G | 5778'4" | 70 | - | - | 51.0 | - | 43.0 | - | 0.21 |
| 27 | G-3 | | 44 | 0.31 | 93 | 53.4 | 2.4 | 50.0 | 4.7 | 0.14 |
| 27 | G-1 | | 39 | 0.43 | 71 | 56.2 | 5.2 | 53.0 | 4.9 | 0.11 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 34 | K | 5800'11" | 1100 | - | - | 48.7 | - | 34.5 | - | 1.30 |
| 34 | K-1 | | 1180 | 0.41 | 94 | 63.0 | 14.3 | 56.5 | 1.8 | 0.69 |
| 34 | L-1 | 5802'10" | 1790 | - | - | 55.8 | - | 50.3 | - | 0.75 |
| 34 | L-1 | | 1790 | 0.33 | 100 | 56.9 | 1.1 | - | 1.4 | 0.54 |
| 34 | M-1 | 5807'0" | 168 | - | - | 47.5 | - | 44.0 | - | 0.40 |
| 34 | M-1 | | 168 | 0.35 | 100 | 50.0 | 2.5 | - | 4.0 | 0.10 |
| 34 | M | | 347 | 0.34 | 96 | 52.5 | 5.0 | 48.0 | 1.7 | 0.25 |
| 34 | N | 5809'6" | 1811 | - | - | 56.4 | - | 33.0 | - | 0.90 |
| 34 | N | | 1811 | 0.33 | 100 | 57.5 | 1.1 | - | 1.2 | 0.72 |
| 34 | N-1 | | 1450 | 0.38 | 95 | 59.3 | 2.9 | 57.0 | 1.3 | 0.90 |

TABLE 7

RESIDUAL RESISTANCE FACTORS (FRr) SERIES 1 SAMPLES

$$\frac{(Kw \text{ before polymer})}{(Kw \text{ after polymer})}$$

| Sample No. | Ko at resid. water sat | FRr | |
|---|---|---|---|
| 70 | 2625 | 3.2 | |
| 69 | 1711 | 2.3 | |
| 31 | 1250 | 1.2 | |
| 50 | 760 | 2.3 | |
| 15 | 663 | 1.1 | Average = 2.1 |
| 51 | 489 | 1.3 | |
| 27 | 429 | 2.5 | |
| 60 | 274 | 1.4 | |
| 73 | 224 | 5.1 | |
| 35 | 224 | 2.4 | |
| 75 | 182 | 1.2 | |
| 32 | 114 | 1.5 | |
| 72 | 98 | 1.5 | |
| 37 | 88 | 1.8 | |
| 42 | 79 | 1.7 | |
| 26 | 46 | 3.0 | |
| 33 | 44 | 2.8 | |
| 43 | 38 | 2.8 | |
| 6 | 31 | 6.4 | Average = 3.5 |
| 67 | 31 | 3.7 | |
| 10 | 31 | 3.8 | |
| 58 | 29 | 2.5 | |
| 36 | 28 | 2.7 | |
| 22 | 15 | 5.9 | |
| 39 | 15 | 3.2 | |
| 14 | 7 | 6.6 | |

Table 8

Concentration of polymer in effluent by turbidity
(Series 1 samples)

| Sample Number | Amount of polymer injected (P.V.) | Polymer concentration in effluent (ppm) after initial polymer injection occurred | | | | |
|---|---|---|---|---|---|---|
| | | $\frac{1}{3}$ P.V. throughput | $\frac{2}{3}$ P.V. throughput | 1 P.V. throughput | $1\frac{1}{3}$ P.V. throughput | $1\frac{2}{3}$ P.V. throughput |
| 13 | 0.37 | 0 | 265 | 140 | 30 | 0 |
| 21 | 0.30 | 0 | 140 | 120 | 120 | 0 |
| 37 | 0.63 | 0 | 500 | 175 | 140 | 0 |
| 67 | 0.66 | 0 | 20 | 210 | 120 | 0 |

Table 9

Effect of Polymer* Injection on Permeability to Oil and Water

| Sample reference | Permeability to Moonie water before polymer injection (md) | Permeability to Moonie water after polymer injection (md) | Reduction in water permeability due to polymer (%) | Permeability to oil before polymer (md) | Permeability to oil after polymer (md) | Reduction in oil permeability due to polymer (%) |
|---|---|---|---|---|---|---|
| J-3 | 50 | 18 | 64 | 237 | 208 | 12 |
| D-3 | 6 | 1 | 82 | 32 | 27 | 16 |
| F-3 | 29 | 22 | 24 | 364 | 349 | 4 |
| G-3 | 14 | 3 | 81 | 44 | 42 | 4 |
| Averages | | | 63 | | | 9 |

*Polymer used was 500 ppm "Pusher 700" in Moonie water

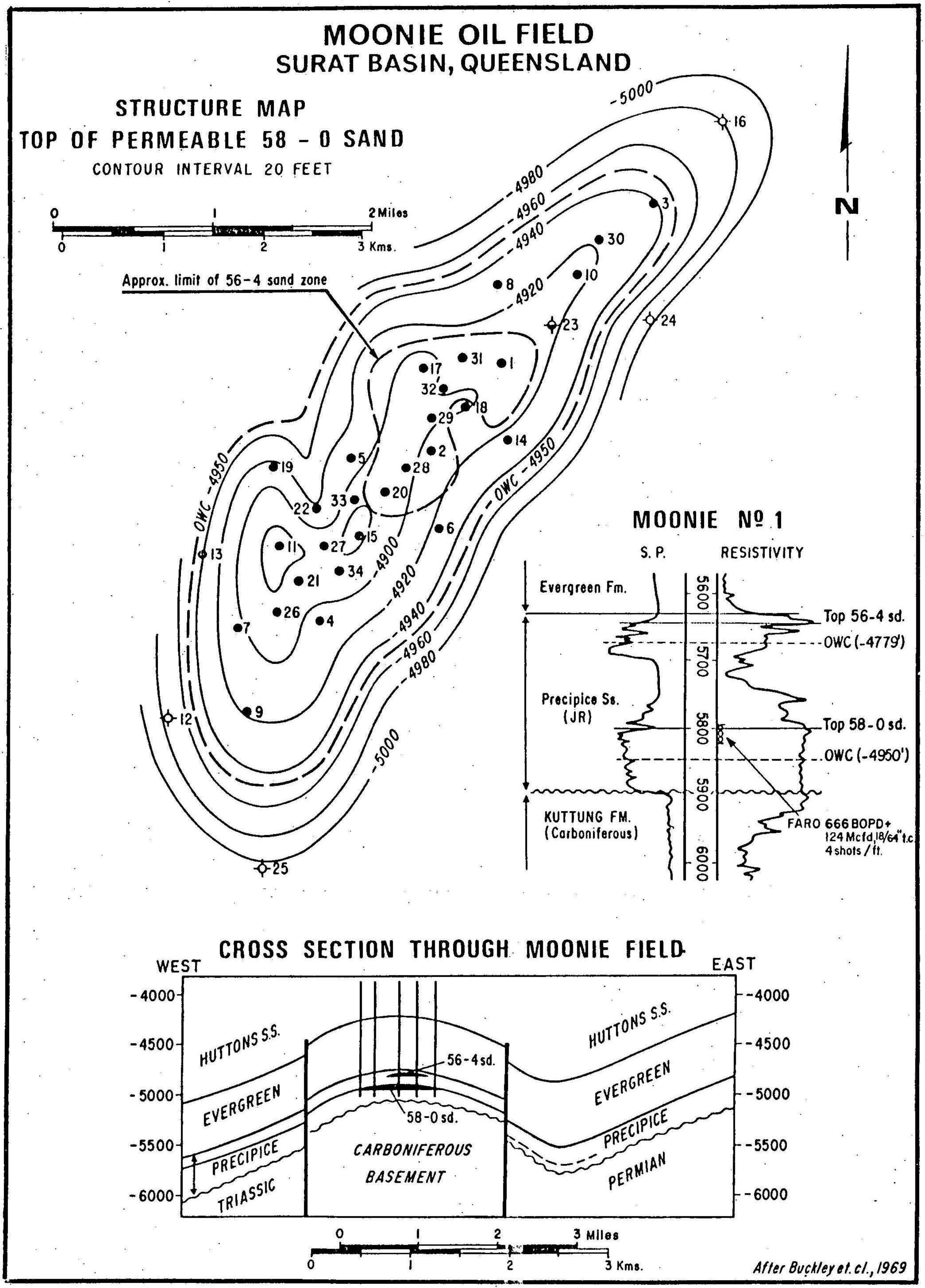
Table 10

Manifold tests - simultaneous flow through two plugs

| Well Number | Depth (feet) | Permeability to nitrogen (Md) | Residual water saturation (% P.V.) | Water cut on polymer introduction (%) | Amount of polymer entering plug (P.V.) | Oil recovery % oil in place | | Reduction in permeability after polymer (%) | | Residual resistance factor (Fw)/(Fwp) | Fluid throughput (P.V.) | | Polymer oil recovery (% oil in place) | Water cut at test completion |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | before polymer | after polymer | to water | to oil | | before polymer | at test completion | | % |
| 27* | 5809'11" | 175 | 49 | 73 | 0.07 | 27.3 | 48.2 | 48 | 19 | 1.9 | 0.23 | 1.95 | 20.9 | 99.0 |
| 4* | 5806'7" | 1177 | 41 | 100 | 0.83 | 25.2 | 39.8 | 56 | 4 | 2.9 | 4.61 | 32.3 | 4.6 | 100 |
| * - set 1 | | | | | | | | | | | | | | |
| 26** | 5771'10" | 86 | 46 | 52 | 0.03 | 29.3 | 42.1 | 38 | 9 | 1.6 | 0.33 | 1.35 | 12.8 | 97.0 |
| 26** | 5790'0" | 439 | 49 | 100 | 0.62 | 34.0 | 43.6 | 56 | 23 | 2.3 | 5.25 | 9.67 | 9.6 | 99.6 |
| ** - set 2 | | | | | | | | | | | | | | |
| 27*** | 5776'4" | 97 | 47 | 56 | 0.08 | 32.1 | 50.4 | 29 | 0 | 1.4 | 0.39 | 1.65 | 18.3 | 99.0 |
| 27*** | 5805'9" | 357 | 46 | 99 | 0.69 | 34.0 | 44.7 | 54 | 3 | 2.2 | 5.75 | 24.8 | 10.7 | 99.9 |

*** - set 3

FIGURE 1




COURTESY L.R. BEDDOES

FIGURE 2

## ENHANCED RECOVERY TECHNIQUES

| TYPE | METHOD | EFFECT | APPLICATION |
|---|---|---|---|
| THERMAL | STEAM INJECTION INSITU COMBUSTION | LOWER $U_o$ | HEAVY OIL, SHALLOW DEPTH |
| LPG MISCIBLE | PROPANE, THEN WATER & GAS | IMPROVE MISCIBILITY & $K_o$ | THIN SHALLOW FORM LOW K, LOW $U_o$ |
| ENRICHED GAS MISCIBLE | $C_1$ to $C_6$, THEN WATER & GAS | IMPROVE MISCIBILITY & $K_o$ | VOLATILE OIL, LOW $U_o$ HIGH RELIEF RESERVOIR |
| HI-PRESSURE LEAN GAS MISCIBLE | CYCLE DRY GAS | VAPORIZE RESIDUAL LIQUID PETROLEUM | VOLATILE UNDERSAT'D OIL LOW K, THIN FORM |

$K_o$ – Permeability to oil

$U_o$ – Viscosity of oil

FIGURE 3

| ENHANCED RECOVERY TECHNIQUES | | | |
|---|---|---|---|
| TYPE | METHOD | EFFECT | APPLICATION |
| $CO_2$ MISCIBLE | CONTINUOUS $CO_2$ OR $CO_2$, THEN WATER & GAS | IMPROVE MISCIBILITY & Ko | HEAVIER (> 25° API) LESS VOLATILE OILS |
| SURFACTANT MICELLAR | SURFACTANT OR MICELLAR SLUG THEN POLYMER & WATER | LOWER INTERFACIAL TENSION | SUITED TO RESERVOIRS WHERE WATERFLOODS SUCCEED |
| POLYMER | POLYMER & WATER | IMPROVE MOBILITY RATIO | STRATIFIED & HETEROGENEOUS RESERVOIRS |
| MICRO BIOLOGICAL | PRODUCE INSITU VISCOSIFIERS & SURFACTANTS | IMPROVE HYDROCARBON FLUID PROPERTIES | LOW TEMPERATURE, LOW PERMEABILITY RESERVOIRS |

Ko – Permeability to oil

Uo – Viscosity of oil

FIGURE 4

# GAS-WATER CAPILLARY PRESSURE

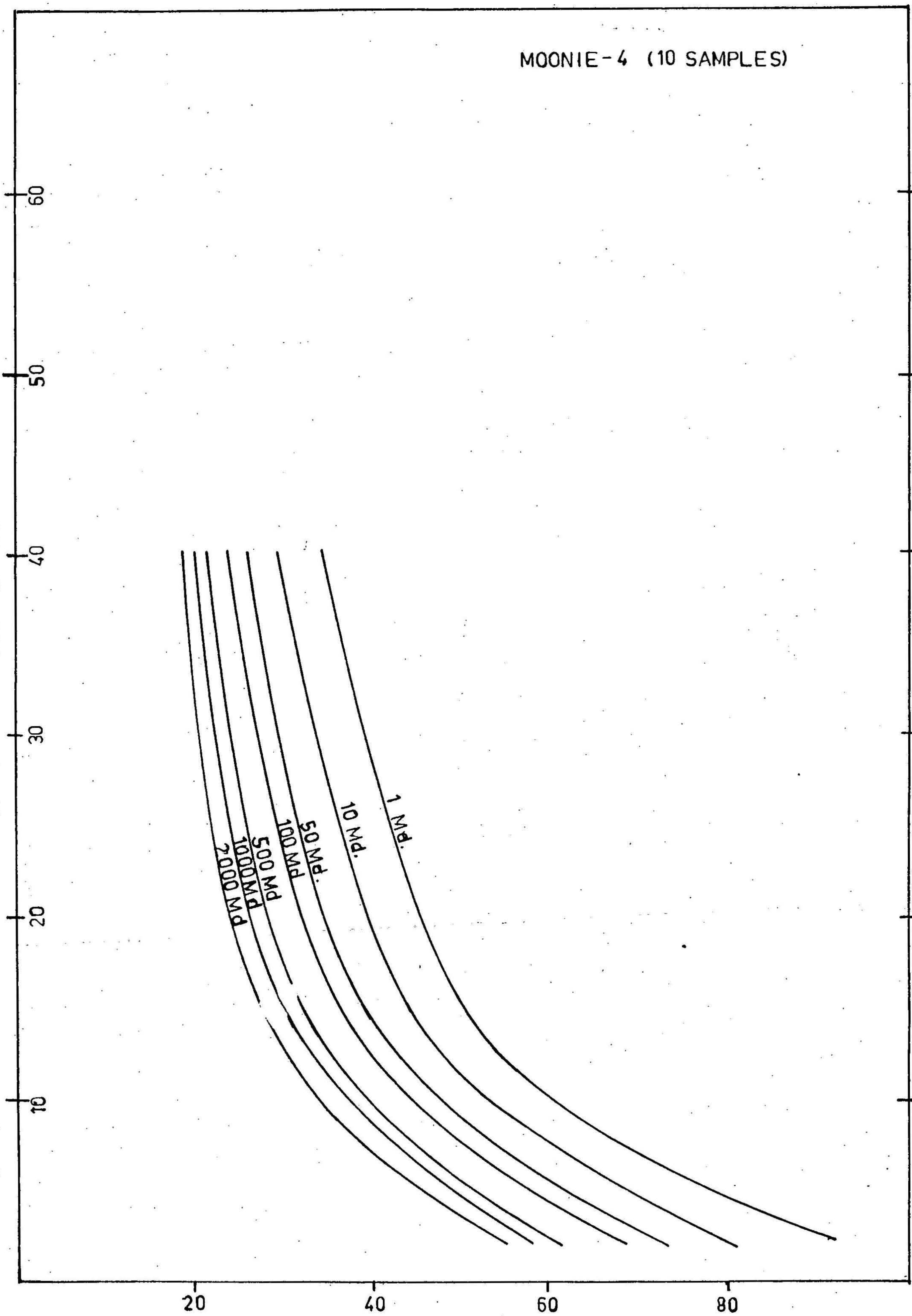
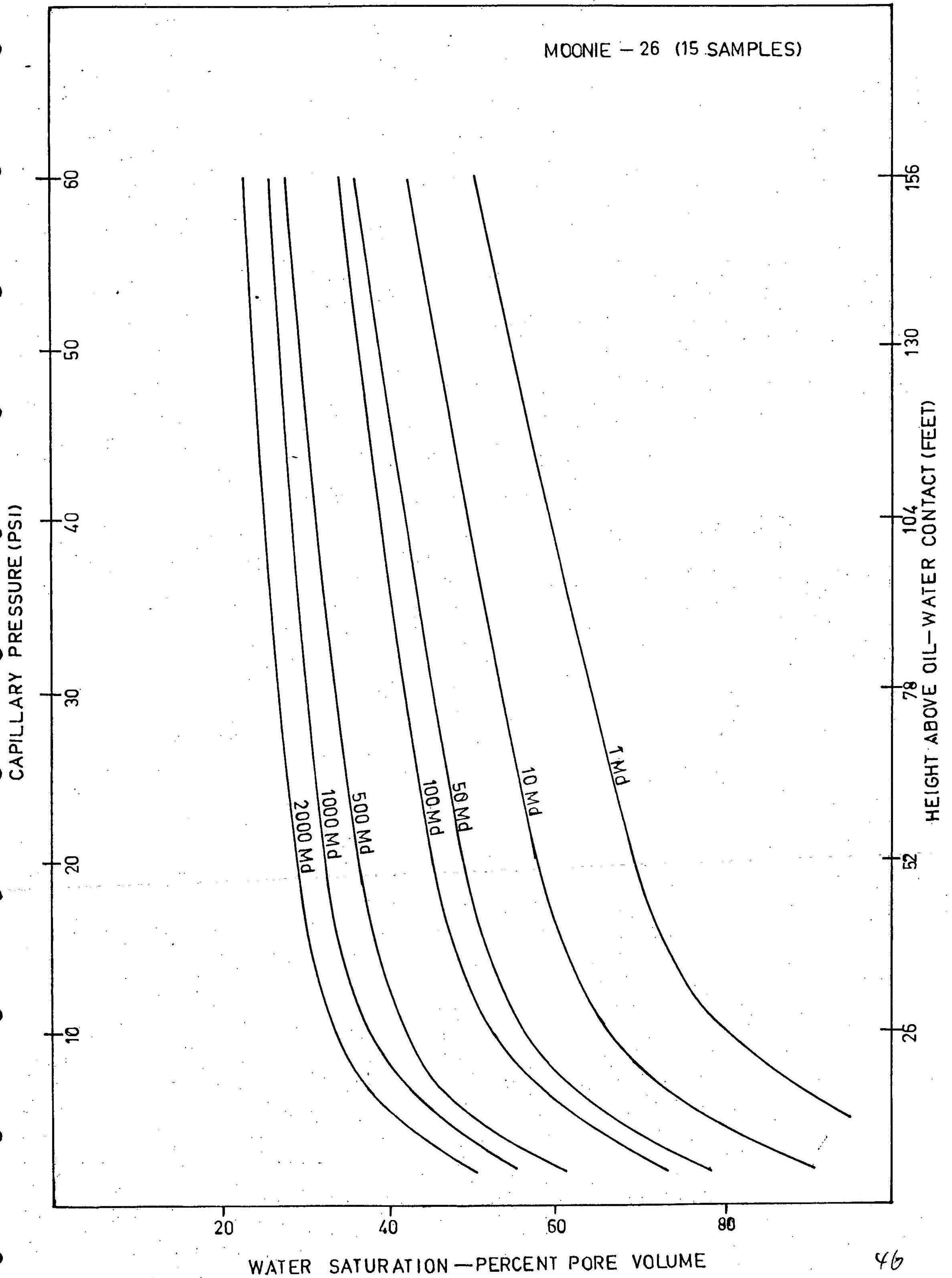


FIGURE 5

# GAS-WATER CAPILLARY PRESSURE




46

FIGURE 6

# GAS-WATER CAPILLARY PRESSURE

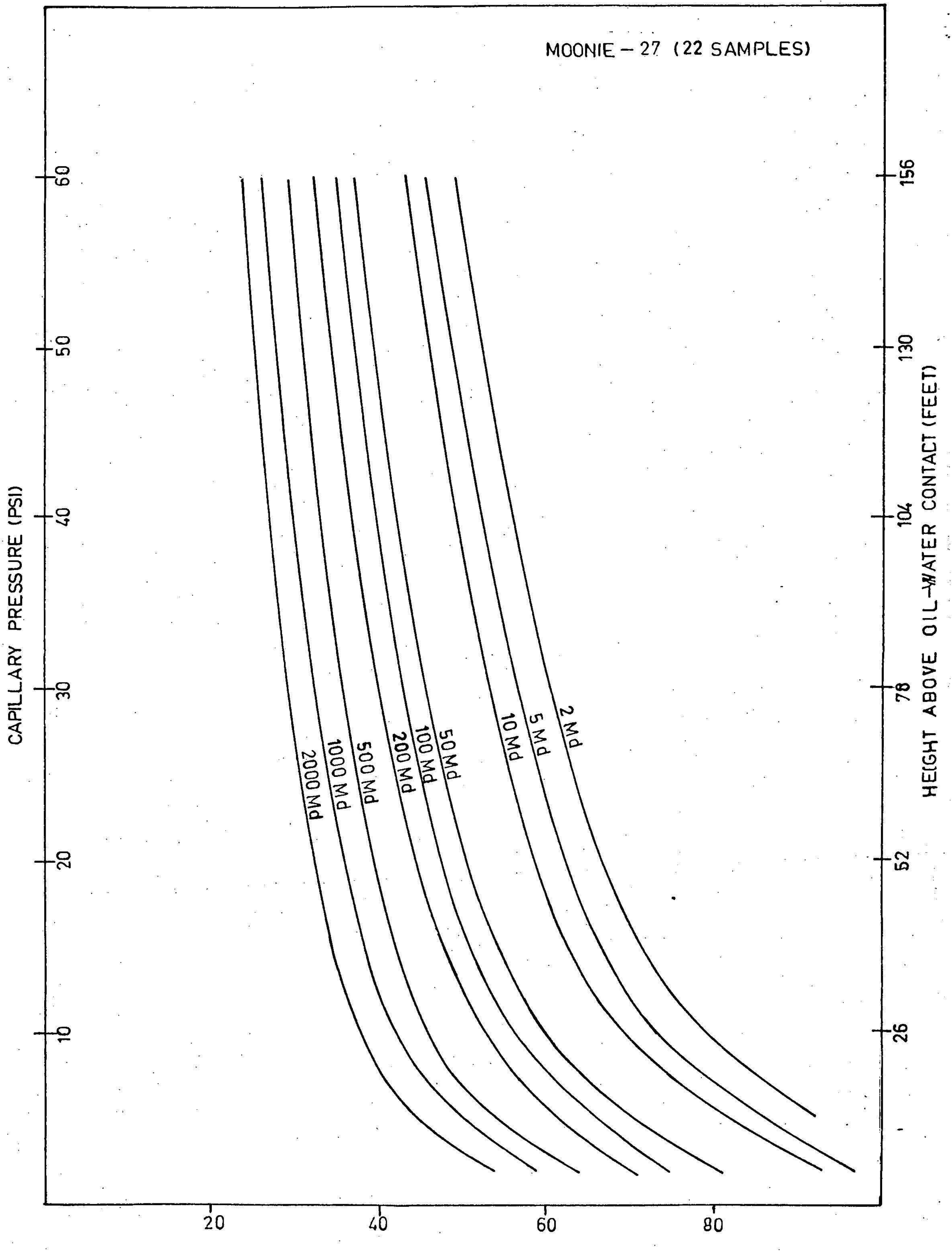


FIGURE 7

# GAS-WATER CAPILLARY PRESSURE

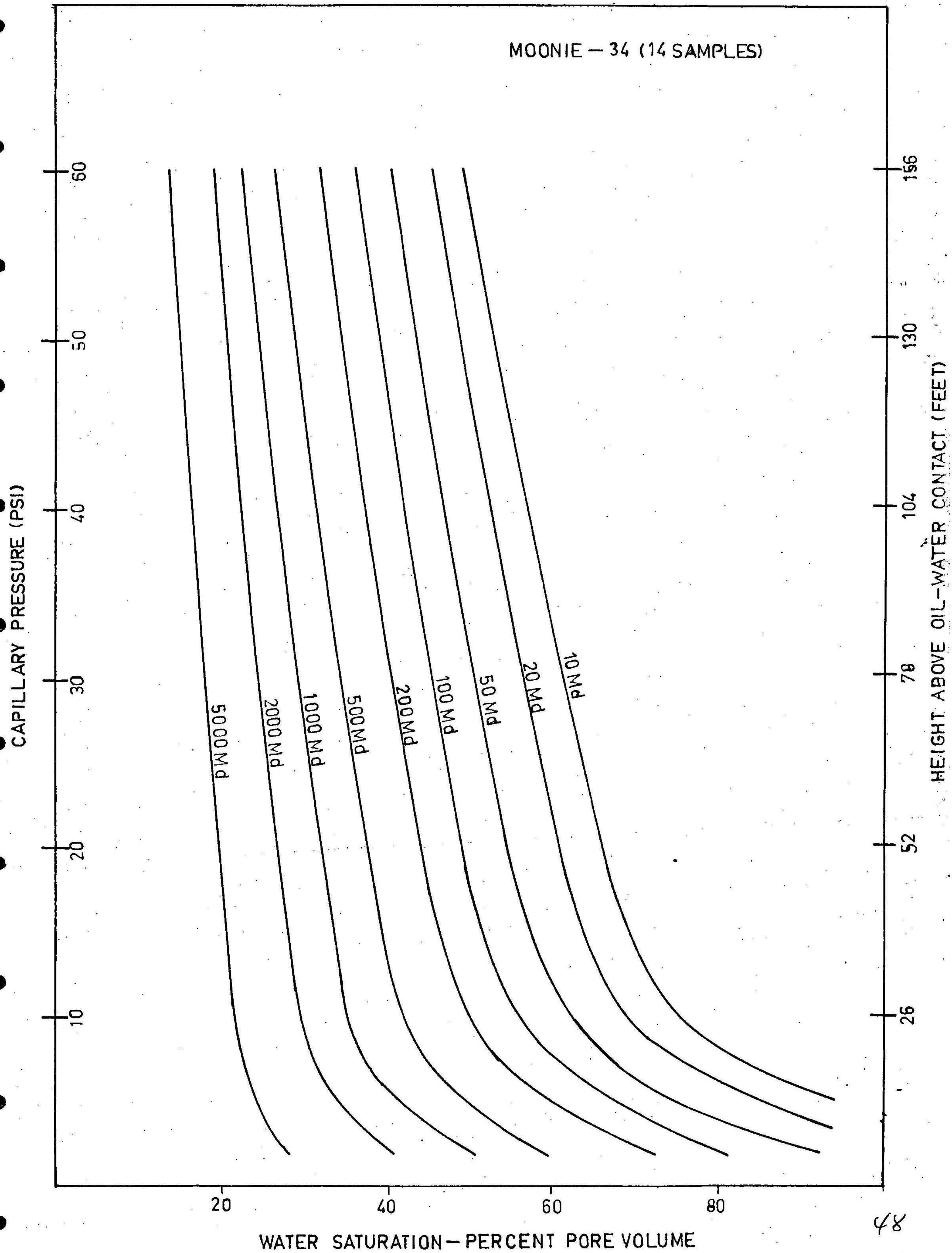


FIGURE 8

# WATER FLOOD SUSCEPTIBILITY

## WELL NAME AND NUMBER - MOONIE No. 4

## DEPTH INTERVAL - 5806 to 5832

POROSITY - 18.6%

PERMEABILITY (Ka) - 478 Md.

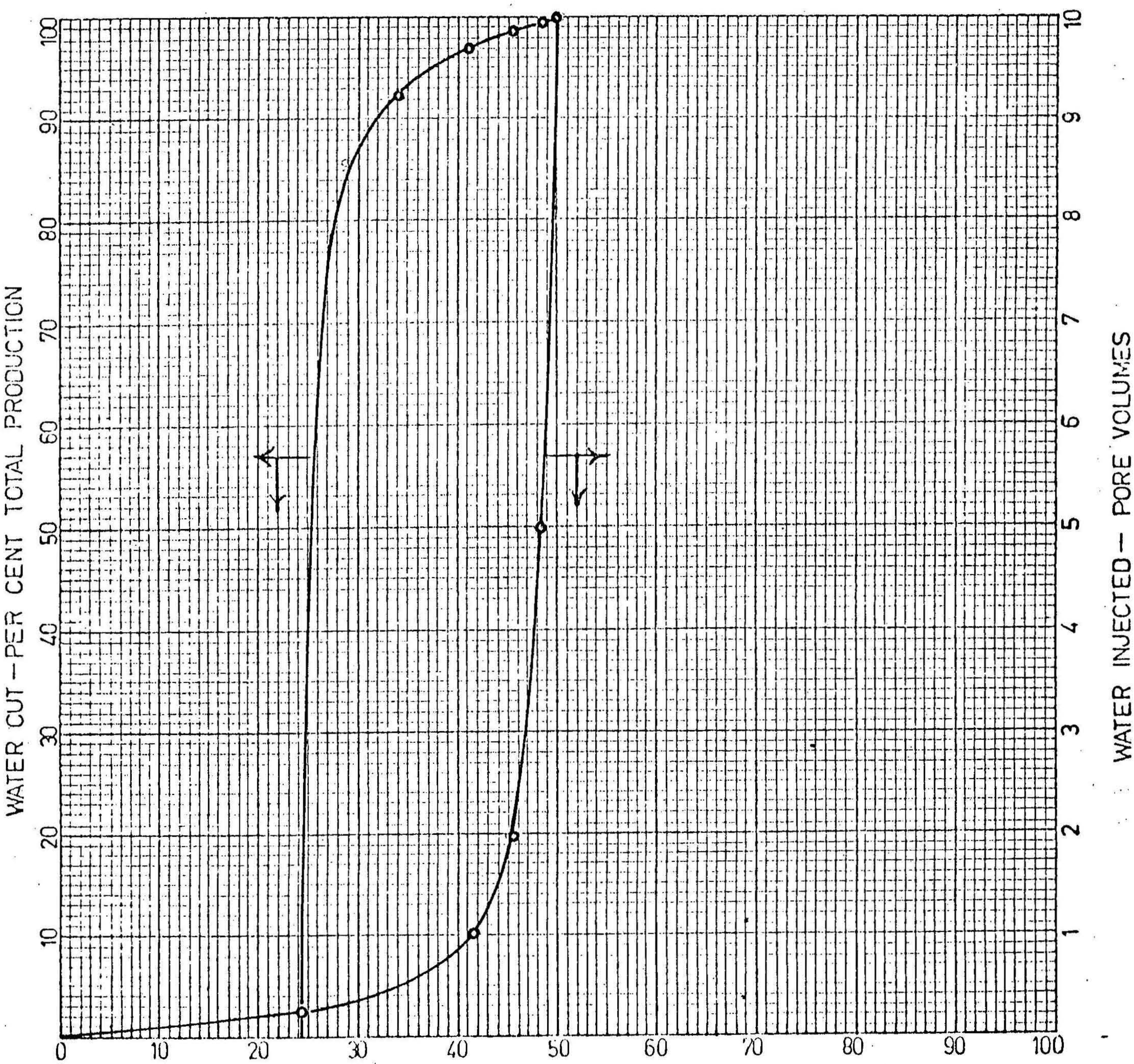


FIGURE 9

# WATER FLOOD SUSCEPTIBILITY

## WELL NAME AND NUMBER - MOONIE No.9

## DEPTH INTERVAL - 5812 to 5831

POROSITY - 16.2 %

PERMEABILITY (Ka) - 306 Md

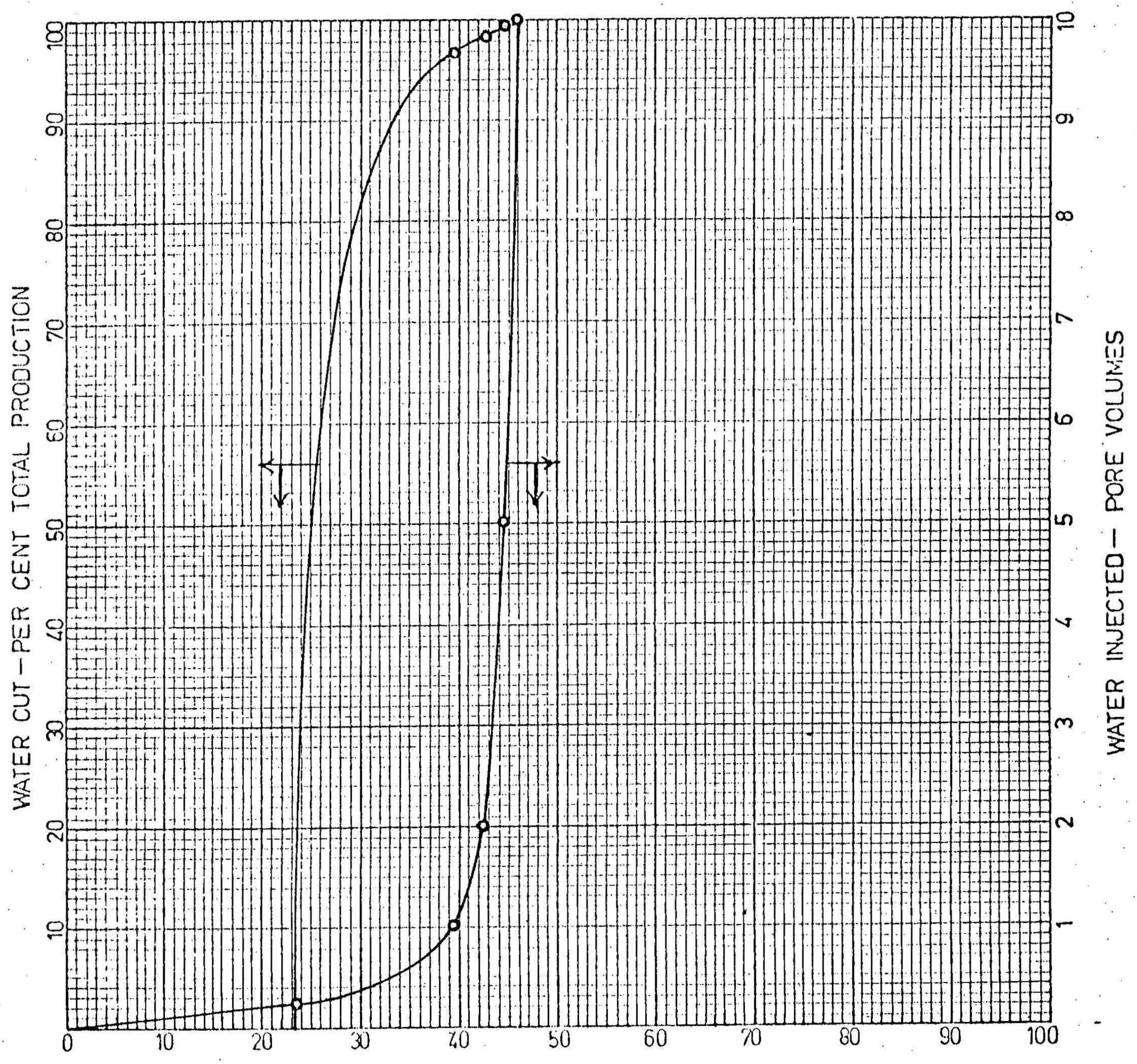


FIGURE 10

# WATER FLOOD SUSCEPTIBILITY

## WELL NAME AND NUMBER – MOONIE No. 13

## DEPTH INTERVAL – 5821 to 5830

POROSITY – 17.7%

PERMEABILITY – (Ka) – 212Md.

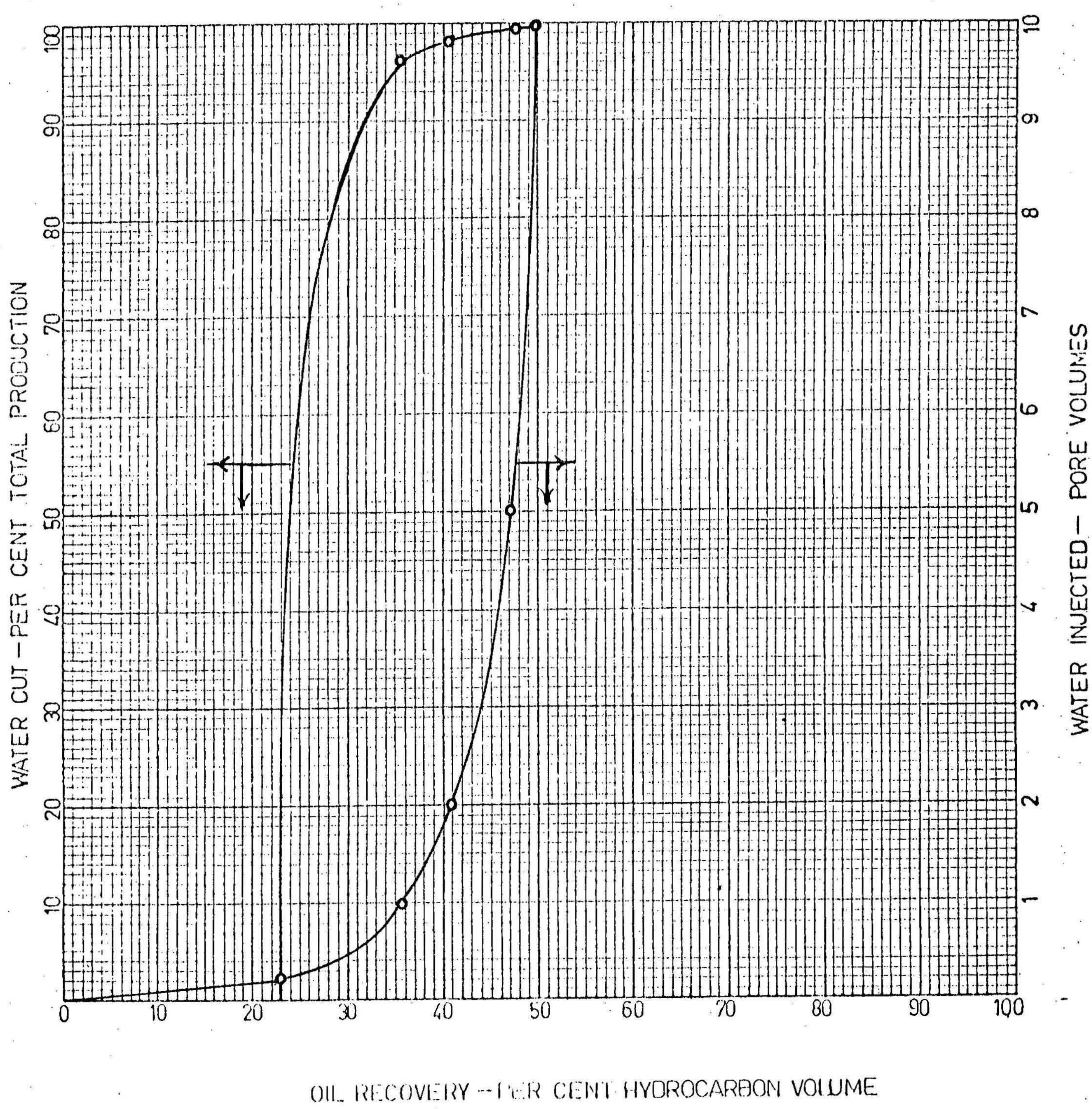


FIGURE 11

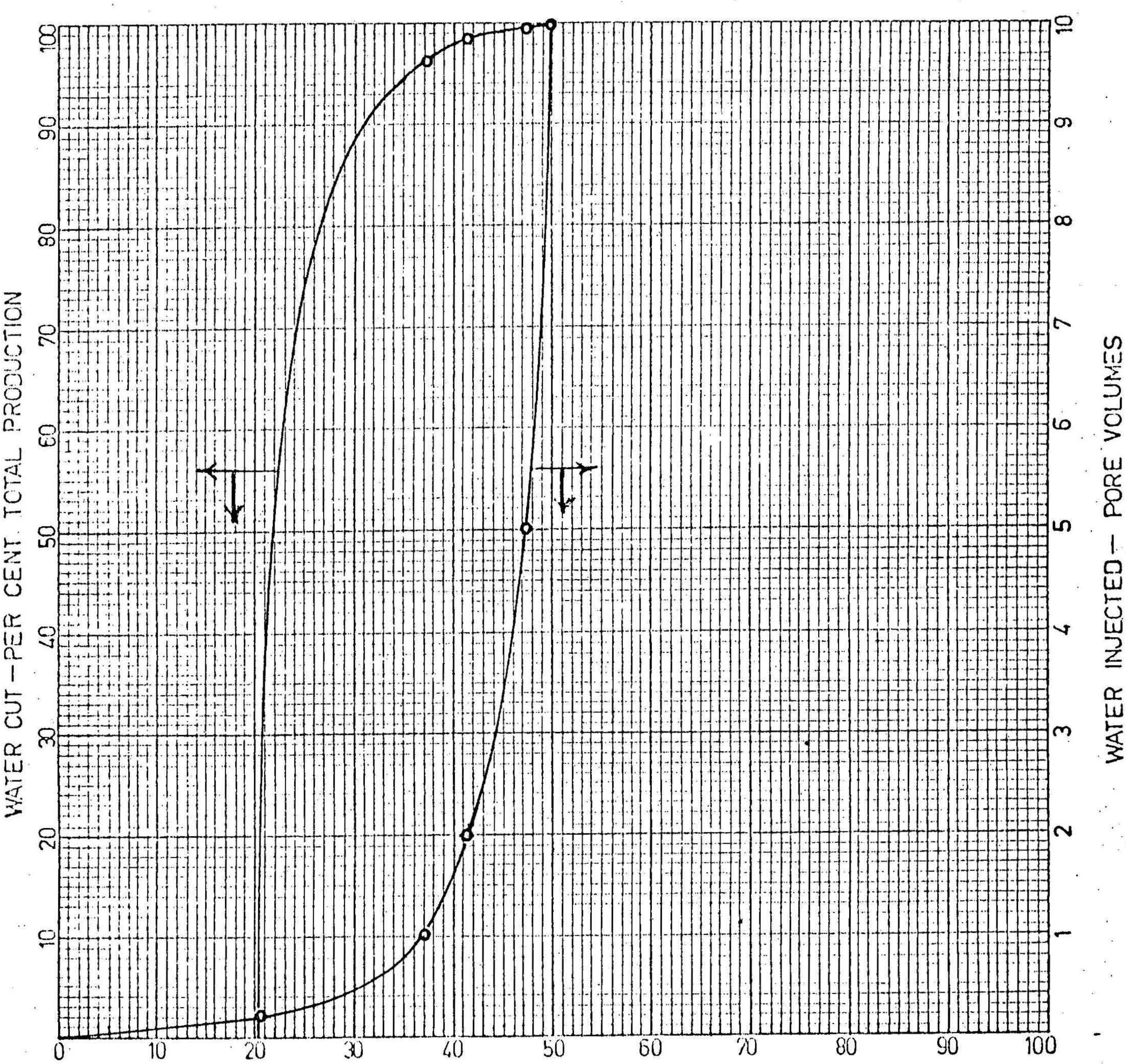
# WATER FLOOD SUSCEPTIBILITY

## WELL NAME AND NUMBER – MOONIE No. 26

## DEPTH INTERVAL – 5768 to 5819

POROSITY – 17.9 %

PERMEABILITY – (Ka) – 433 Md




OIL RECOVERY – PER CENT HYDROCARBON VOLUME

FIGURE 12

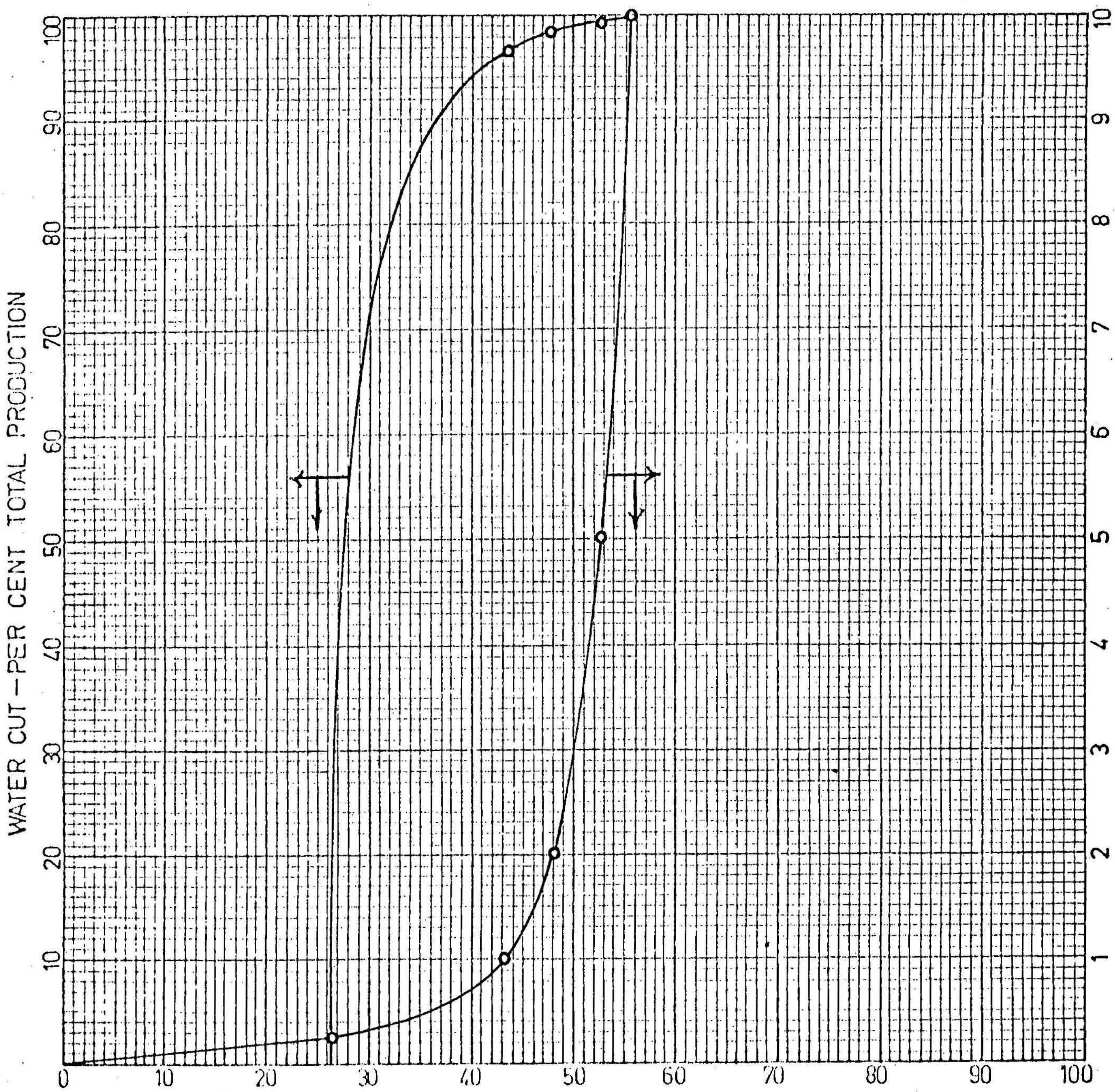
# WATER FLOOD SUSCEPTIBILITY

## WELL NAME AND NUMBER - MOONIE No 27

## DEPTH INTERVAL - 5772 to 5830

POROSITY - 16.6 %

PERMEABILITY - (Ka) - 378 Md




OIL RECOVERY - PER CENT HYDROCARBON VOLUME

FIGURE 13

# WATER FLOOD SUSCEPTIBILITY

## WELL NAME AND NUMBER – MOONIE No. 34

## DEPTH INTERVAL – 5776 to 5829

POROSITY – 17.8 %

PERMEABILITY – (Ka) – 902 Md

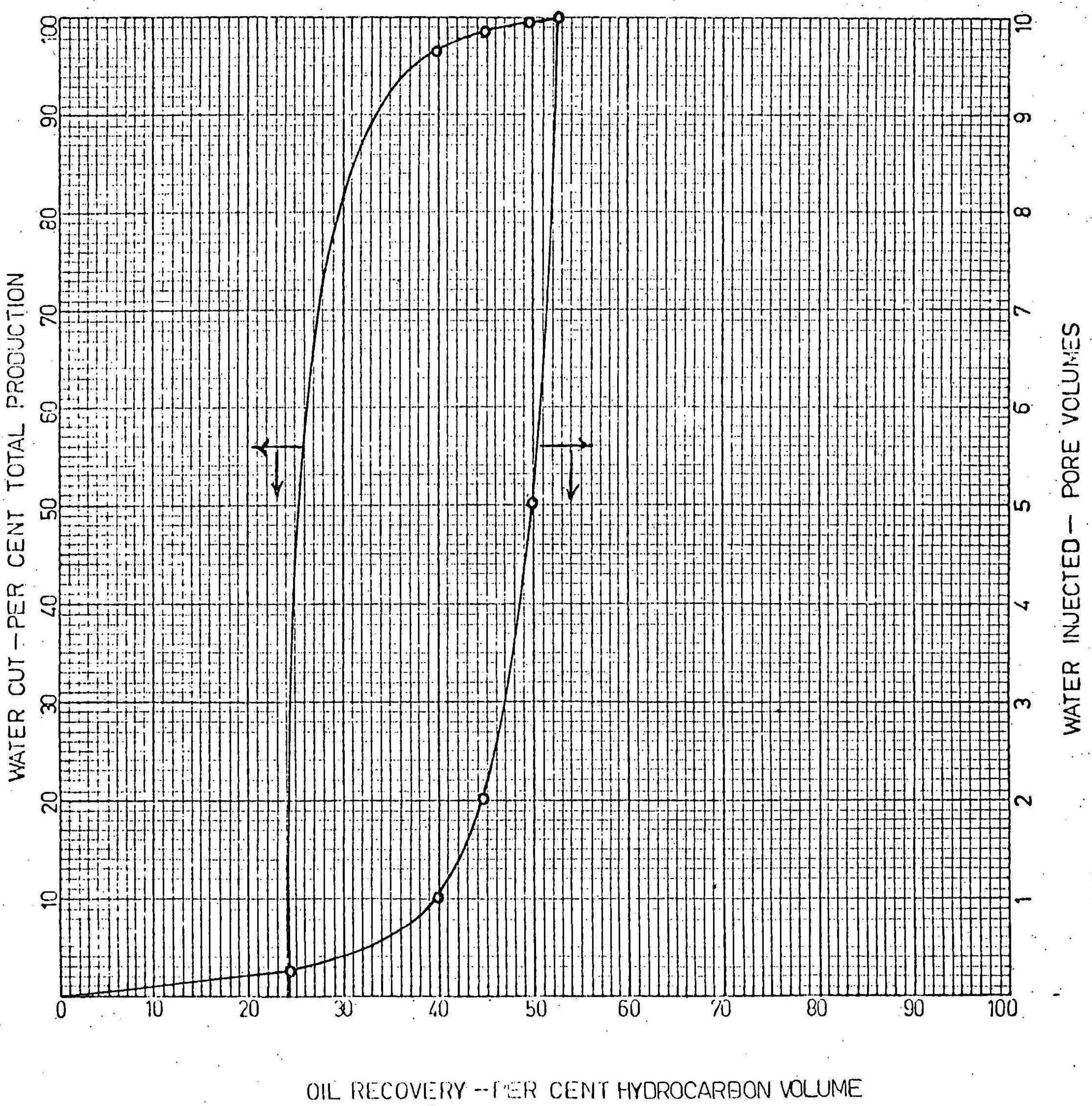
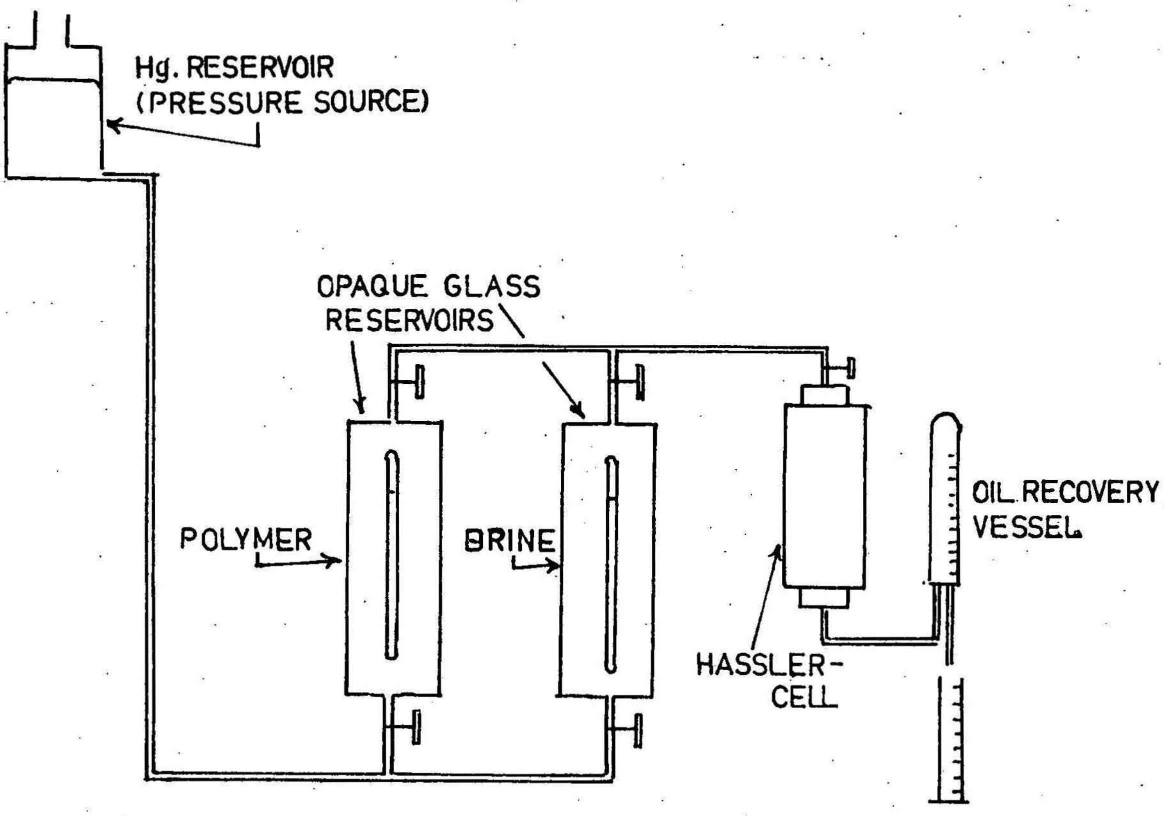


FIGURE 14

## APPARATUS FOR POLYMER FLOODING OF CORE SAMPLES




## SCREEN FACTOR (VISCOSITY) APPARATUS FOR POLYMERS

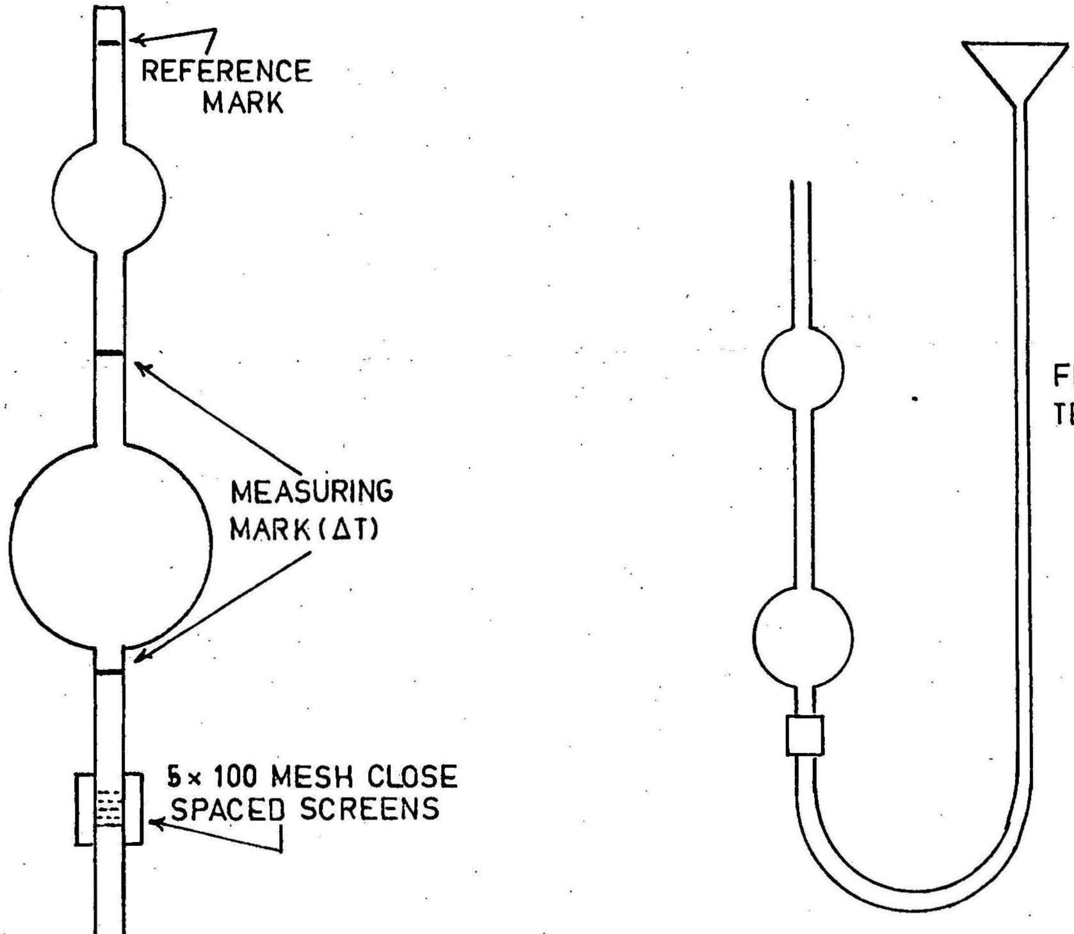


FIGURE 15

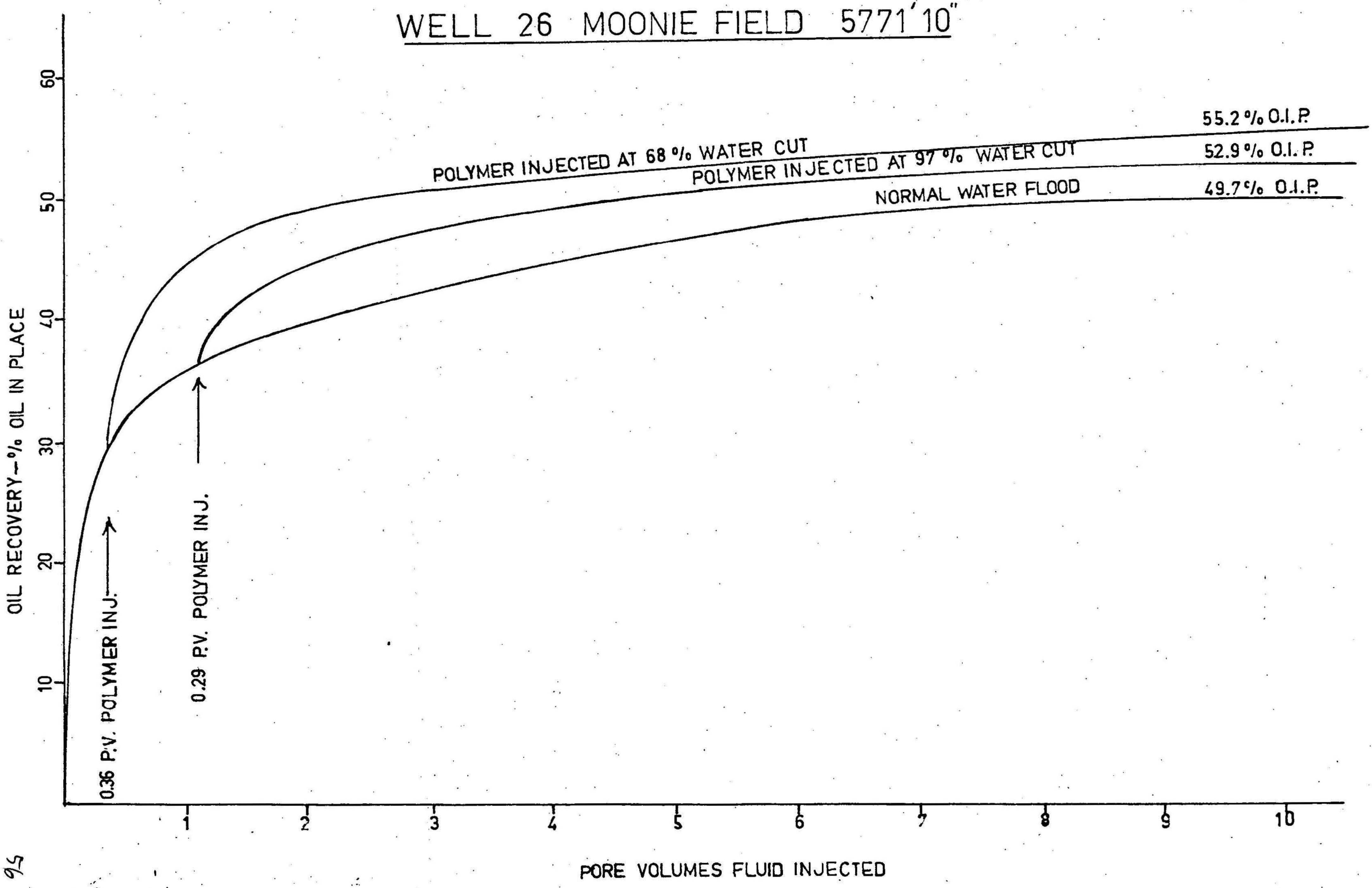
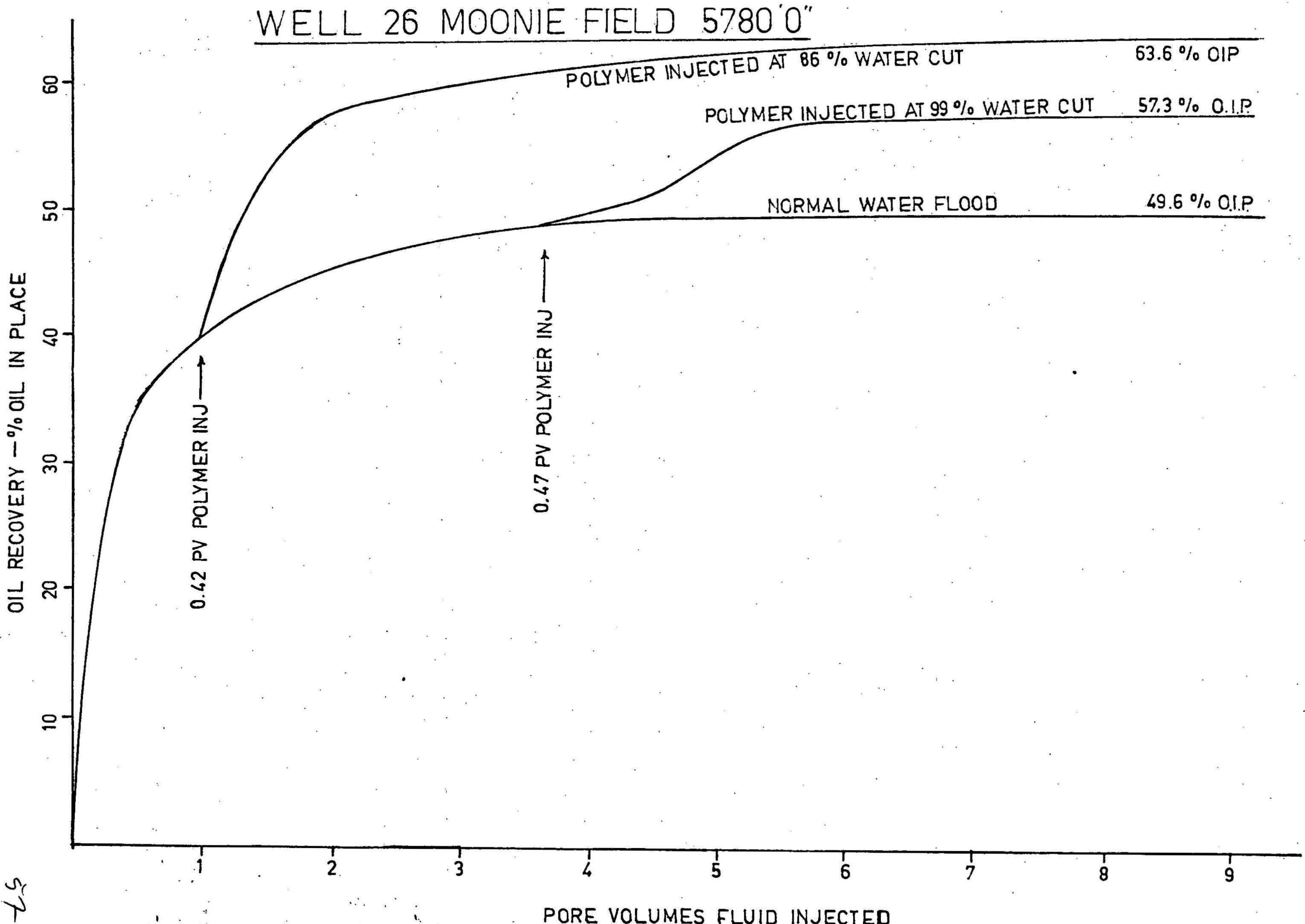
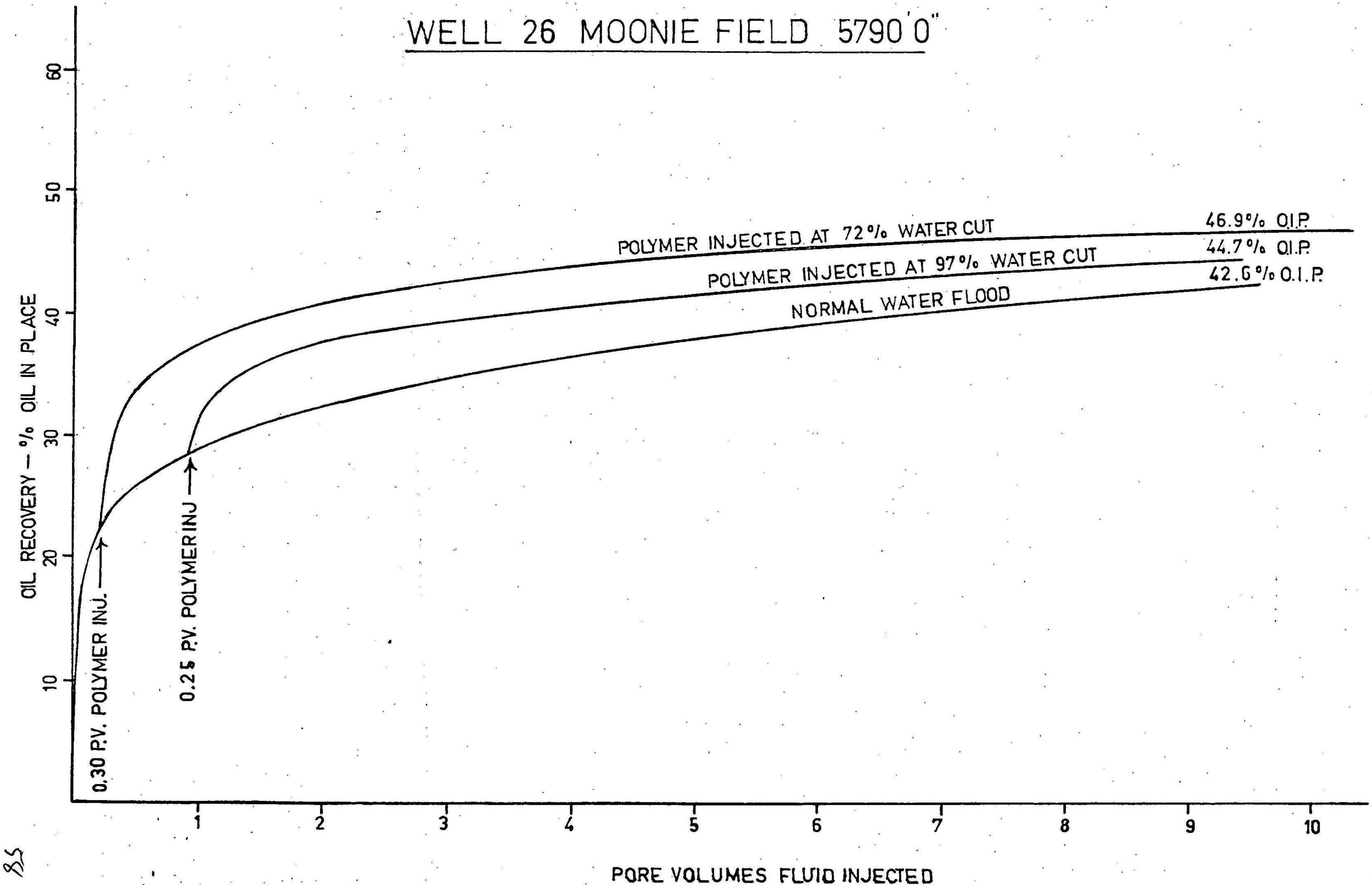

WELL 26 MOONIE FIELD 5771'10"
55.2 % O.I.P.
52.9 % O.I.P.
49.7 % O.I.P.
POLYMER INJECTED AT 68 % WATER CUT
POLYMER INJECTED AT 97 % WATER CUT
NORMAL WATER FLOOD
OIL RECOVERY — % OIL IN PLACE
10
20
30
40
50
60
0.36 P.V. POLYMER INJ.
0.29 P.V. POLYMER INJ.
1
2
3
4
5
6
7
8
9
10
PORE VOLUMES FLUID INJECTED

FIGURE 16


WELL 26 MOONIE FIELD 5780'0"
POLYMER INJECTED AT 86 % WATER CUT
63.6 % OIP
POLYMER INJECTED AT 99 % WATER CUT
57.3 % O.I.P.
NORMAL WATER FLOOD
49.6 % O.I.P.
0.42 PV POLYMER INJ
0.47 PV POLYMER INJ
OIL RECOVERY — % OIL IN PLACE
10
20
30
40
50
60
1
2
3
4
5
6
7
8
9
PORE VOLUMES FLUID INJECTED

57

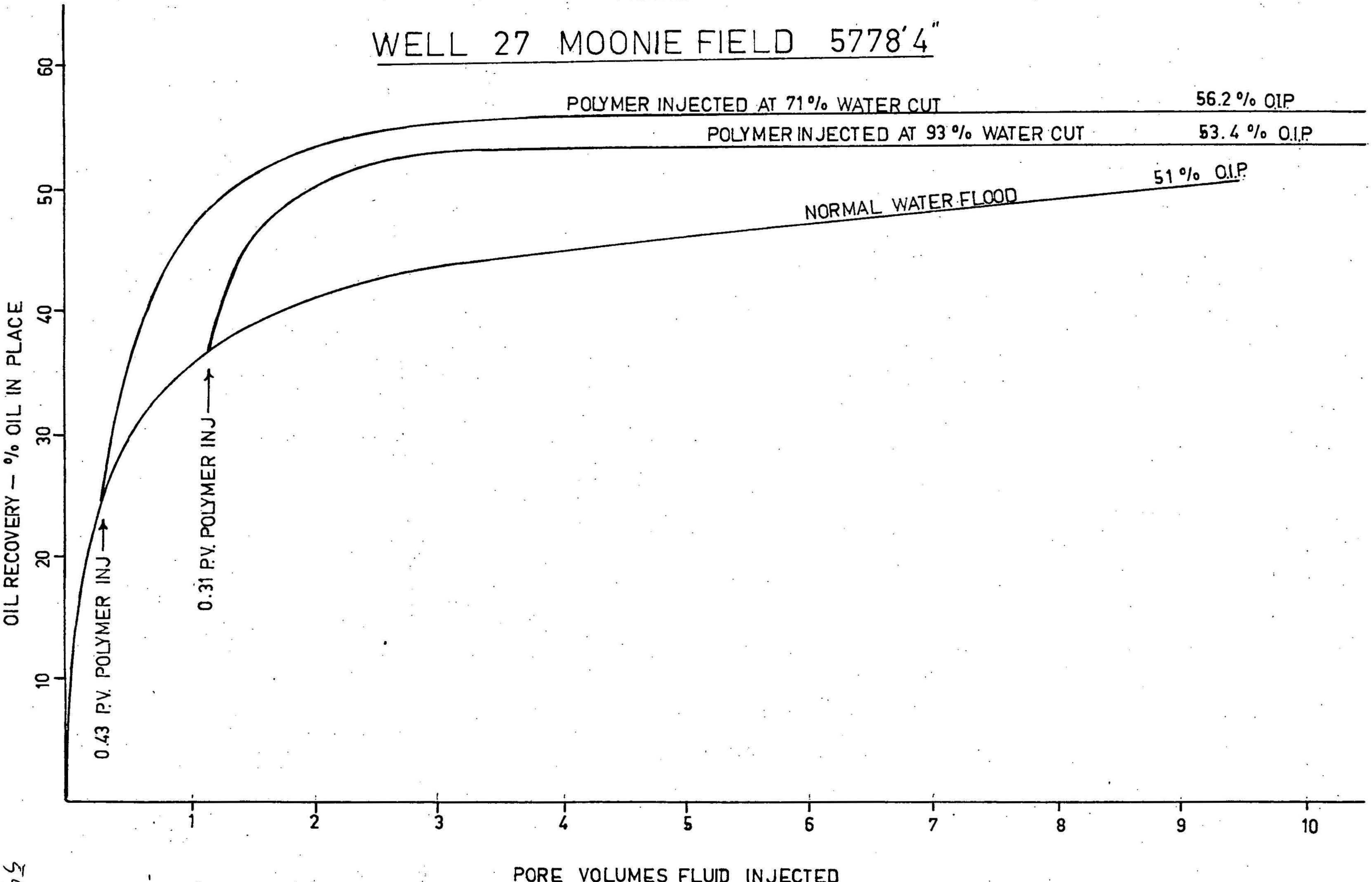
FIGURE 17



WELL 26 MOONIE FIELD 5790'0"
OIL RECOVERY — % OIL IN PLACE
60
50
40
30
20
10
POLYMER INJECTED AT 72% WATER CUT
46.9% O.I.P.
POLYMER INJECTED AT 97% WATER CUT
44.7% O.I.P.
NORMAL WATER FLOOD
42.6% O.I.P.
0.30 P.V. POLYMER INJ.
0.25 P.V. POLYMER INJ
1
2
3
4
5
6
7
8
9
10
PORE VOLUMES FLUID INJECTED


85

FIGURE 18



WELL 27 MOONIE FIELD 5778'4"
POLYMER INJECTED AT 71 % WATER CUT
56.2 % O.I.P.
POLYMER INJECTED AT 93 % WATER CUT
53.4 % O.I.P.
51 % O.I.P.
NORMAL WATER FLOOD
0.43 P.V. POLYMER INJ
0.31 P.V. POLYMER INJ
OIL RECOVERY – % OIL IN PLACE
60
50
40
30
20
10
1
2
3
4
5
6
7
8
9
10
PORE VOLUMES FLUID INJECTED

FIGURE 19

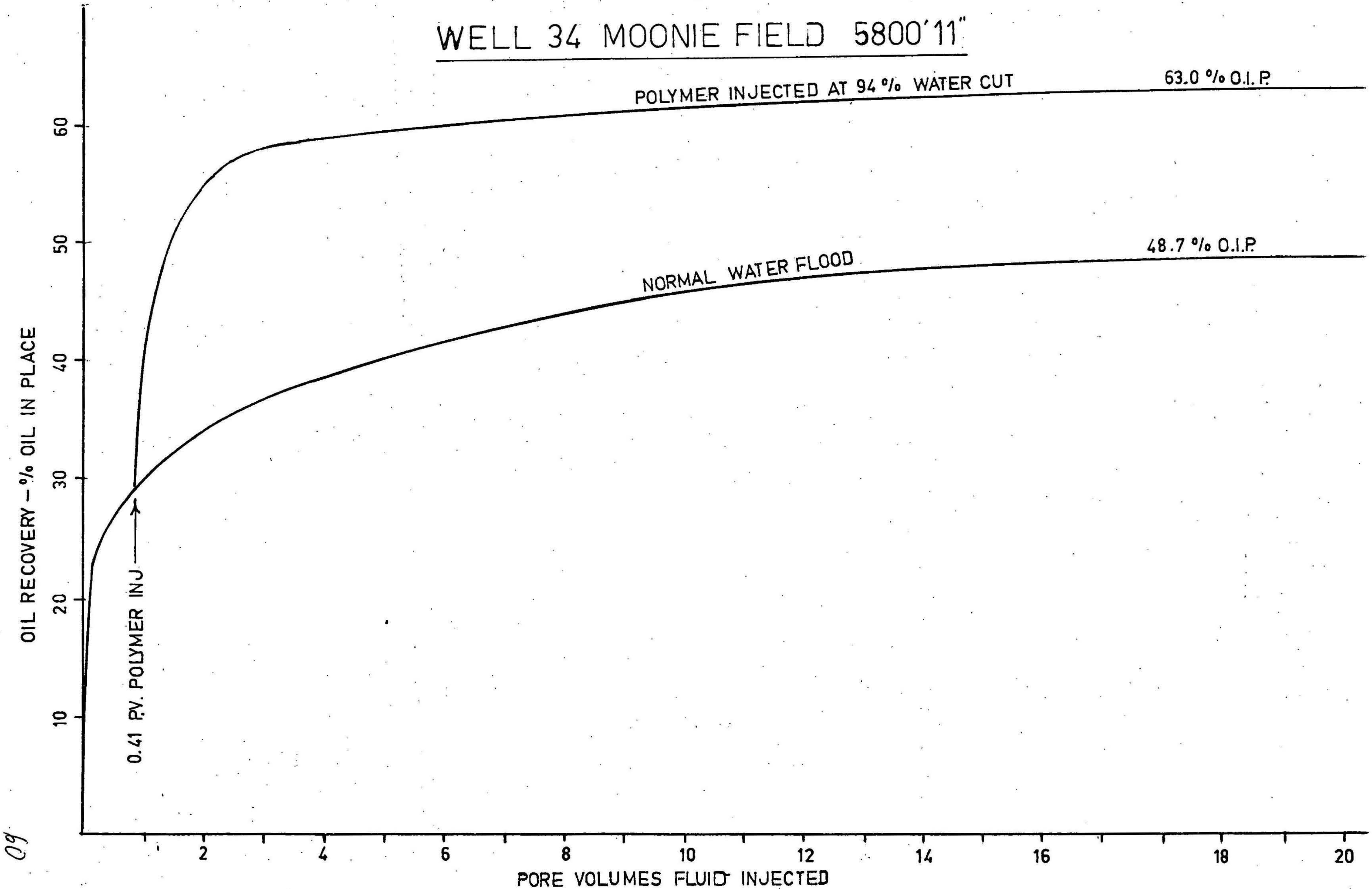

WELL 34 MOONIE FIELD 5800'11"
POLYMER INJECTED AT 94 % WATER CUT
63.0 % O.I.P.
NORMAL WATER FLOOD
48.7 % O.I.P.
0.41 P.V. POLYMER INJ
OIL RECOVERY – % OIL IN PLACE
PORE VOLUMES FLUID INJECTED
10
20
30
40
50
60
2
4
6
8
10
12
14
16
18
20

FIGURE 20

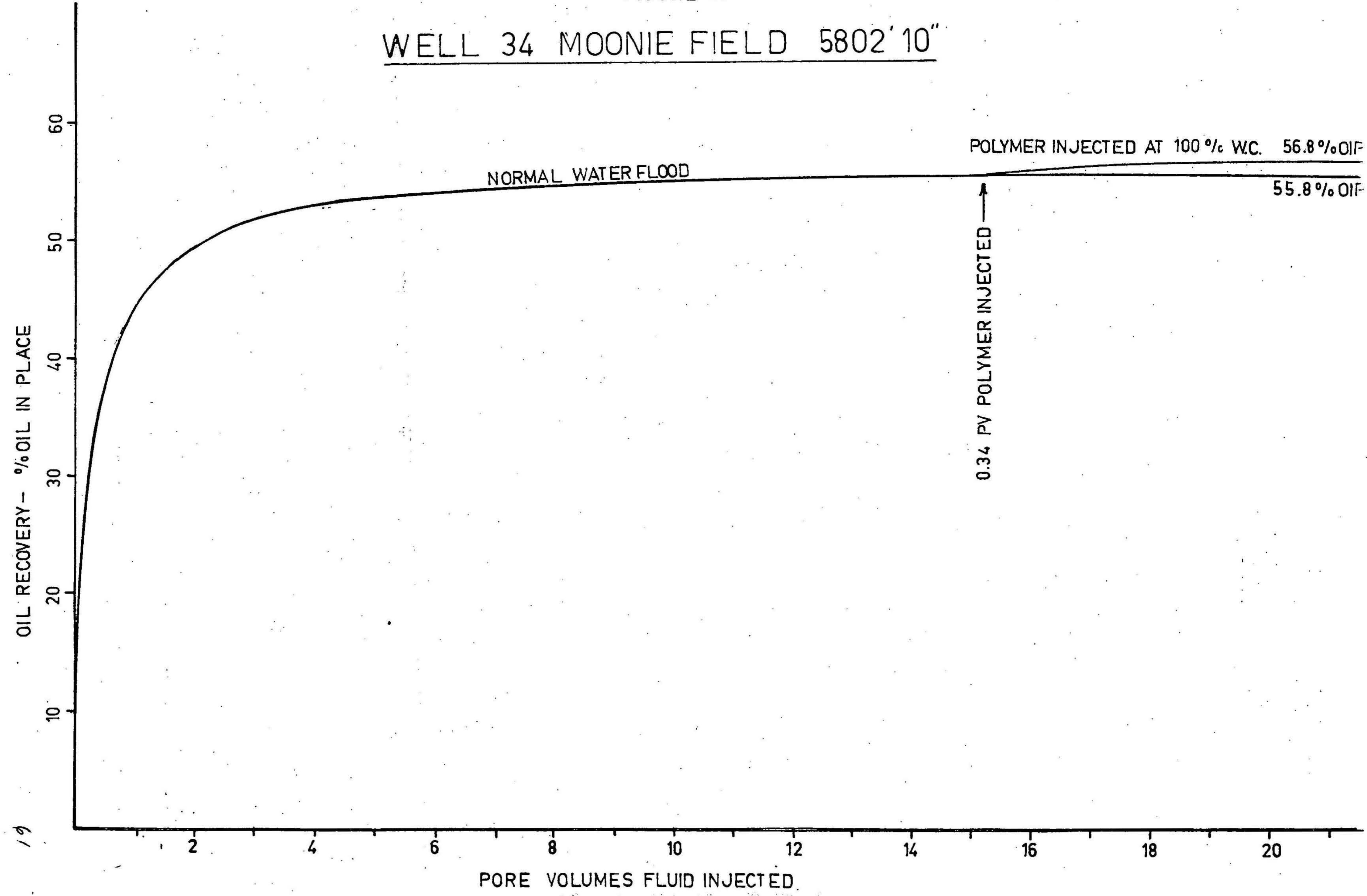
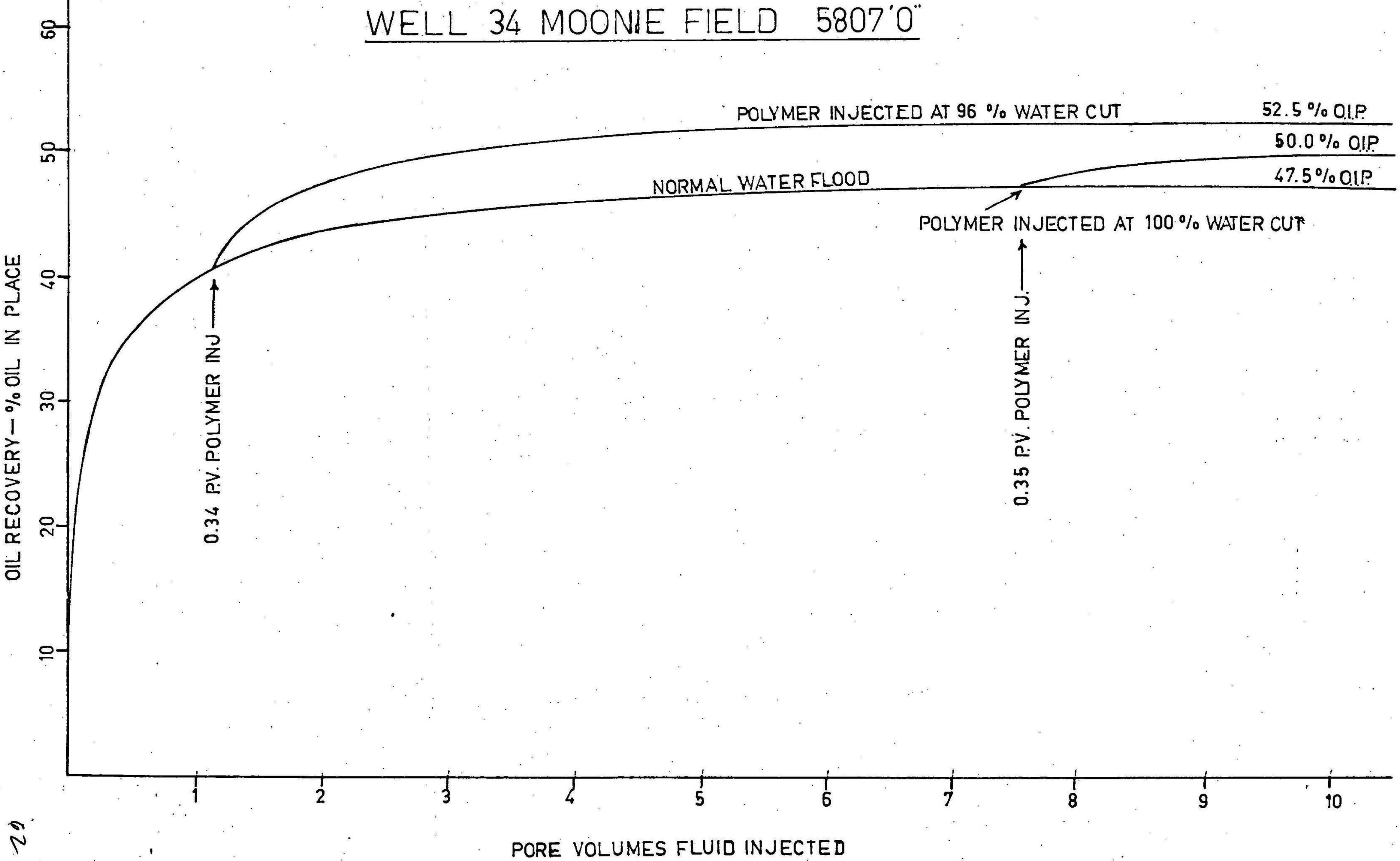

WELL 34 MOONIE FIELD 5802' 10"
OIL RECOVERY - % OIL IN PLACE
10
20
30
40
50
60
NORMAL WATER FLOOD
POLYMER INJECTED AT 100 % W.C. 56.8 % OIP
55.8 % OIP
0.34 PV POLYMER INJECTED
2
4
6
8
10
12
14
16
18
20
PORE VOLUMES FLUID INJECTED

FIGURE 21


WELL 34 MOONIE FIELD 5807'0"
POLYMER INJECTED AT 96 % WATER CUT
52.5 % O.I.P.
50.0 % O.I.P.
47.5 % O.I.P.
NORMAL WATER FLOOD
POLYMER INJECTED AT 100 % WATER CUT
0.34 P.V. POLYMER INJ
0.35 P.V. POLYMER INJ.
OIL RECOVERY — % OIL IN PLACE
PORE VOLUMES FLUID INJECTED
10
20
30
40
50
60
1
2
3
4
5
6
7
8
9
10

29

FIGURE 22

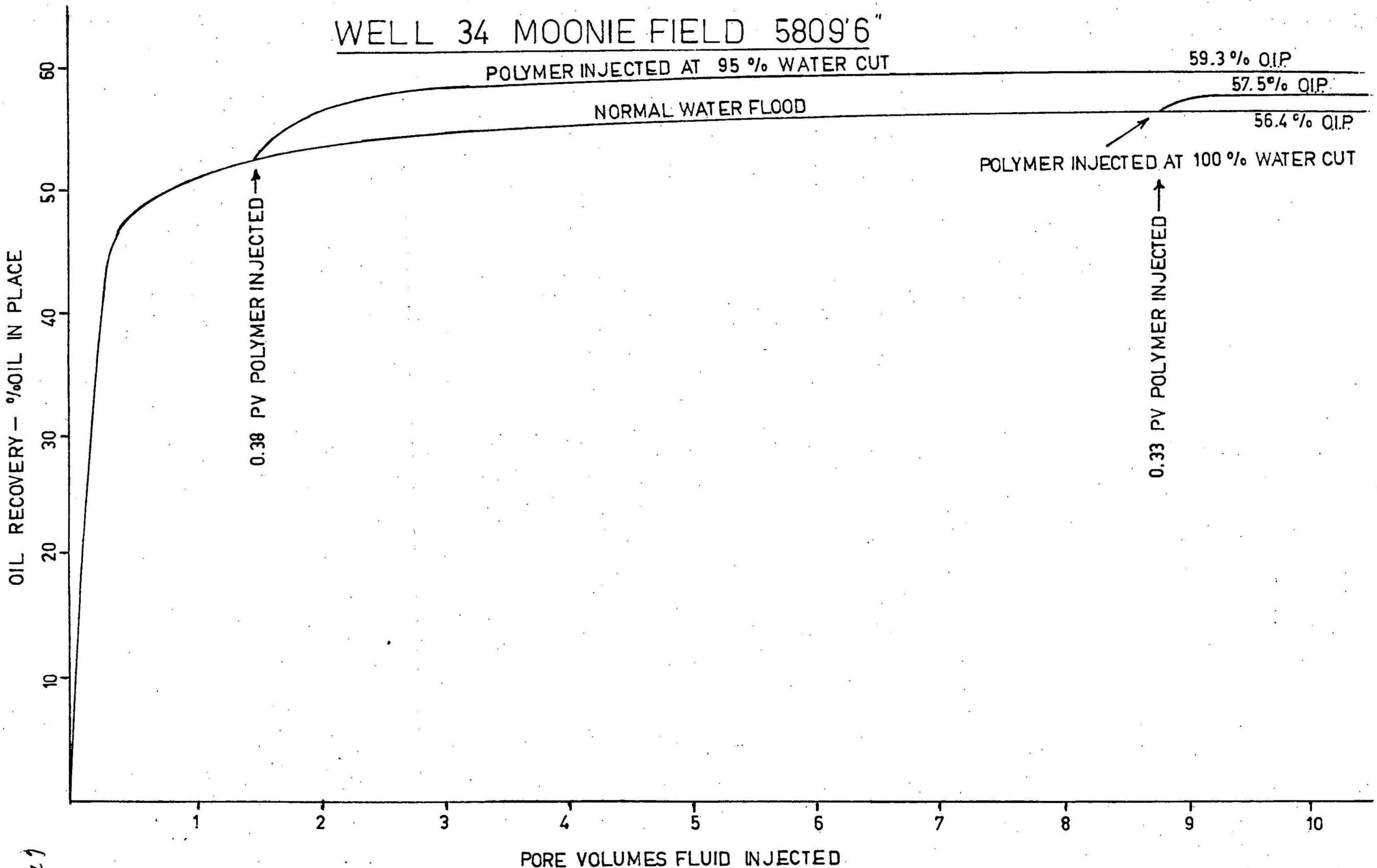
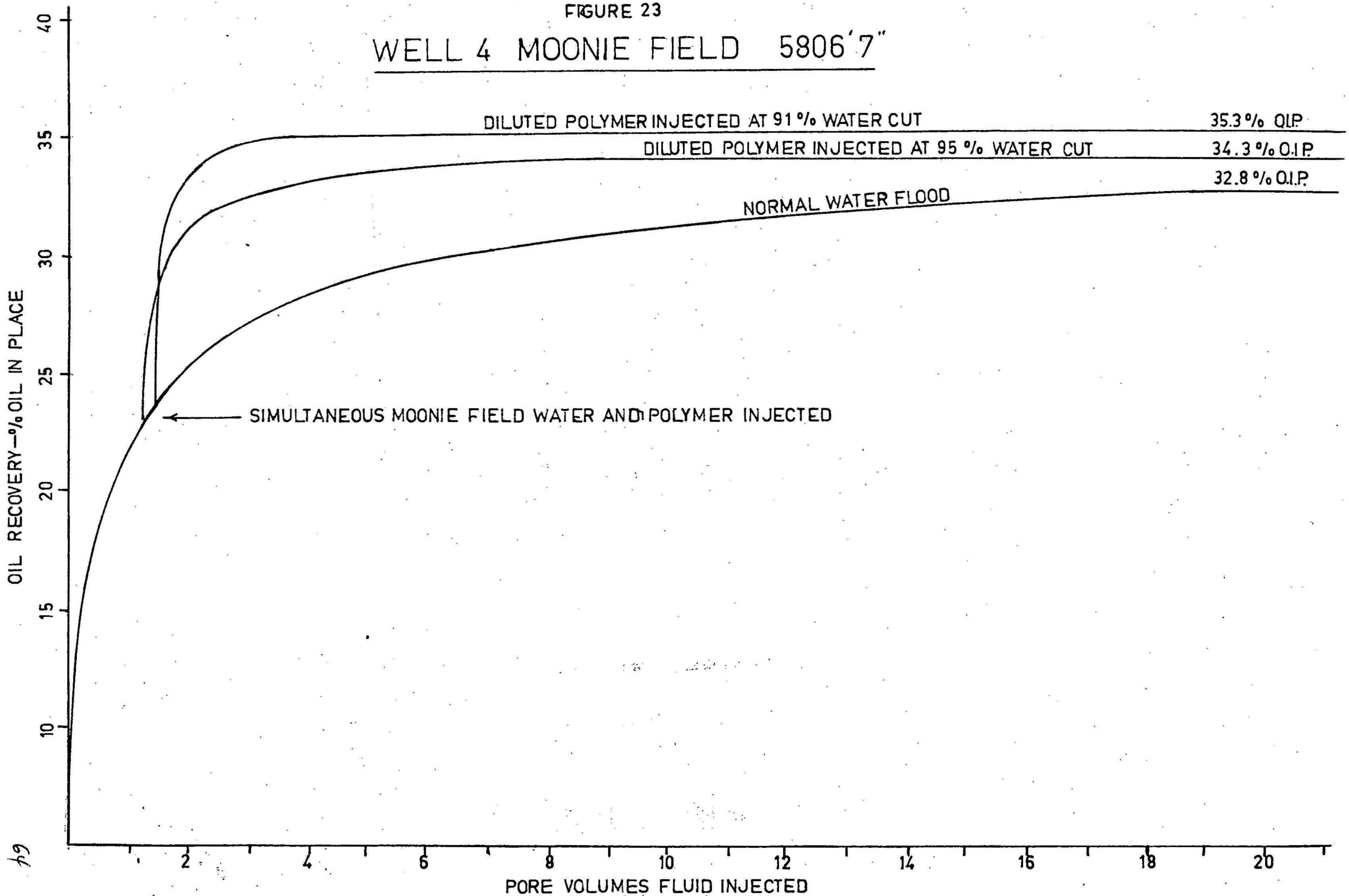

WELL 34 MOONIE FIELD 5809'6"
POLYMER INJECTED AT 95 % WATER CUT
59.3 % O.I.P
57.5% O.I.P
NORMAL WATER FLOOD
56.4 % O.I.P
POLYMER INJECTED AT 100 % WATER CUT
0.38 PV POLYMER INJECTED
0.33 PV POLYMER INJECTED
OIL RECOVERY – %OIL IN PLACE
10
20
30
40
50
60
1
2
3
4
5
6
7
8
9
10
PORE VOLUMES FLUID INJECTED

FIGURE 23


WELL 4 MOONIE FIELD 5806'7"
DILUTED POLYMER INJECTED AT 91 % WATER CUT
35.3 % OIP
DILUTED POLYMER INJECTED AT 95 % WATER CUT
34.3 % O.I.P.
32.8 % O.I.P.
NORMAL WATER FLOOD
SIMULTANEOUS MOONIE FIELD WATER AND POLYMER INJECTED
OIL RECOVERY—% OIL IN PLACE
40
35
30
25
20
15
10
2
4
6
8
10
12
14
16
18
20
PORE VOLUMES FLUID INJECTED

Distribution List - 1978/107

| | | |
|---|---|---|
| Director (m/s) | - | 1 (original) |
| Library | - | 2 |
| File (PEB) | - | 1 |
| Queensland Department of Mines | - | 1 |
| International Oils Ltd<br>114 Albert Road<br>Melbourne. 3000 | - | 1 |
| Authors | - | 1 ea. |

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