A FOCUSED RELATIVE PERMEABILITY SCAL STUDY DRIVEN BY RESERVOIR MANAGEMENT DECISIONS

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ABSTRACT

Faced with the challenge to generate relative permeability data for a complex reservoir management scenario in an unconsolidated heavy oil reservoir, a SCAL study was devised which focused on measurements that would provide tangible benefits to the operator. The initial guideline required oil-water-gas relative permeability on both oil leg and gas cap core, with no definition of the permutations possible within this remit. By analysis of the possible imbibition and drainage scenarios that might occur in the reservoir and the significance of these processes on final oil recovery, a focused workscope providing maximum value was developed. This saved the time and cost of measuring superfluous data and ensured that data relevant to field management decisions were not missed.

Together with a description of the above analysis, this paper describes the experimental details of reservoir condition water and oil floods in oil leg and gas cap core, with in-situ saturation monitoring. The study used composite cores flooded to S_{wi} against porous plates and with wettability restored in live oil. Water floods were conducted at reservoir advance rates and additional bumped rates. Systematic discrepancies between saturations derived from mass balance and in-situ saturation during water flood were seen. It is postulated that mass balance was erroneous due to hold up of oil in the rig pipework, an effect that would occur to some extent in all core floods, but accentuated by the high viscosity of the oil in this study. Capillary pressure end effects were identified from the in-situ data and proprietary core flood simulation methods were used to correct the relative permeabilities for such effects. Quite significant corrections were made to the relative permeability curves by core flood simulation compared to the JBN derived curves.

Important reservoir management decisions are based on SCAL measurements. In this case water/oil relative permeability data had been measured on the same core in an earlier study eight years previously. This previous study did not benefit from in-situ saturation monitoring nor core flood simulation and so there was uncertainty in the measured relative permeability data. The present study, using "modern" techniques, has given the operator increased confidence in the relative permeability data underpinning reservoir management decisions, along with an associated reduction in risk.

INTRODUCTION

This paper is a case study describing how a SCAL program was developed from the initial enquiry, to discussions to understand the reservoir management scenario, through

to the simulation of the final relative permeability curves relevant to the recovery processes.

The reservoir is an unconsolidated, high quality sandstone with a permeability of approximately 8 Darcies and 33% porosity. The oil is quite viscous of approximately 80cp at reservoir conditions. The oil bearing units are partially overlain by a gas cap and underlain by an aquifer. Thus the SCAL study was complicated by the very nature of the reservoir and special techniques were required for core handling.

The oil was to be produced by water flood via horizontal wells and it was recognised that gas coning could not be avoided if oil was to be produced at economic rates. Thus a number of oil, water and gas imbibition and drainage scenarios could be envisaged. The level of detail provided by the operator was that at least one set of "oil-water-gas relative permeability curves" on both oil and gas cap core should be provided, but other than this the precise selection of measurements was unspecified. A significant input was expected from AEA Technology to tailor the measurements to the relevant reservoir decisions.

ANALYSIS OF THE PRODUCTION SCENARIOS

An analysis of the expected fluid movements in the reservoir was made to ascertain the possible imbibition and drainage scenarios.

Figure 1 shows the reservoir during water flood and gas cap depletion. At this stage the

Figure 1: Waterflood and gas cap depletion
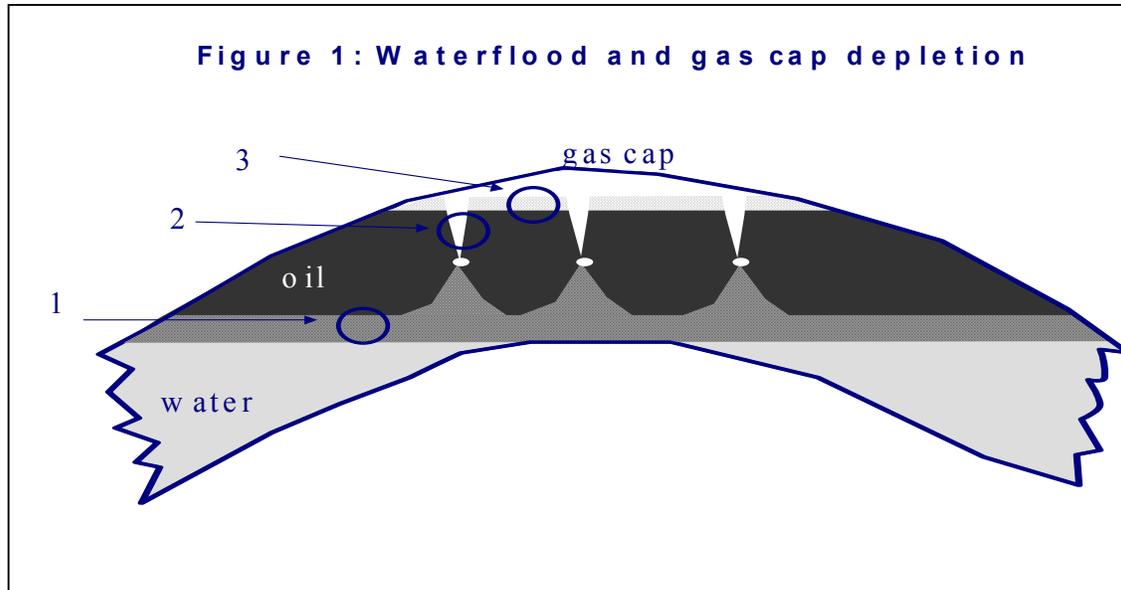
reservoir is being produced by water flood and a water/oil imbibition process is occurring in region 1. As gas cones down to the producer (region 2) a primary drainage gas into oil at $S_w = S_{wi}$ occurs leaving a residual oil saturation. As gas is produced, oil invades the gas cap as a primary oil imbibition into gas at $S_w = S_{wi}$, leaving a trapped gas saturation (Region 3).

Figure 2 represents the situation at some time into the water flood where all free gas has been blown down and wells are flowing at high water cut. A different reservoir process has occurred here compared to the previous situation. In region 4, (the gas cone region) a secondary oil imbibition into gas at $S_w = S_{wi}$ occurs until trapped gas saturation (S_{gt}) is reached.

Figure 2: End of phase 1 waterflood

Figure 3: Phase 2 waterflood
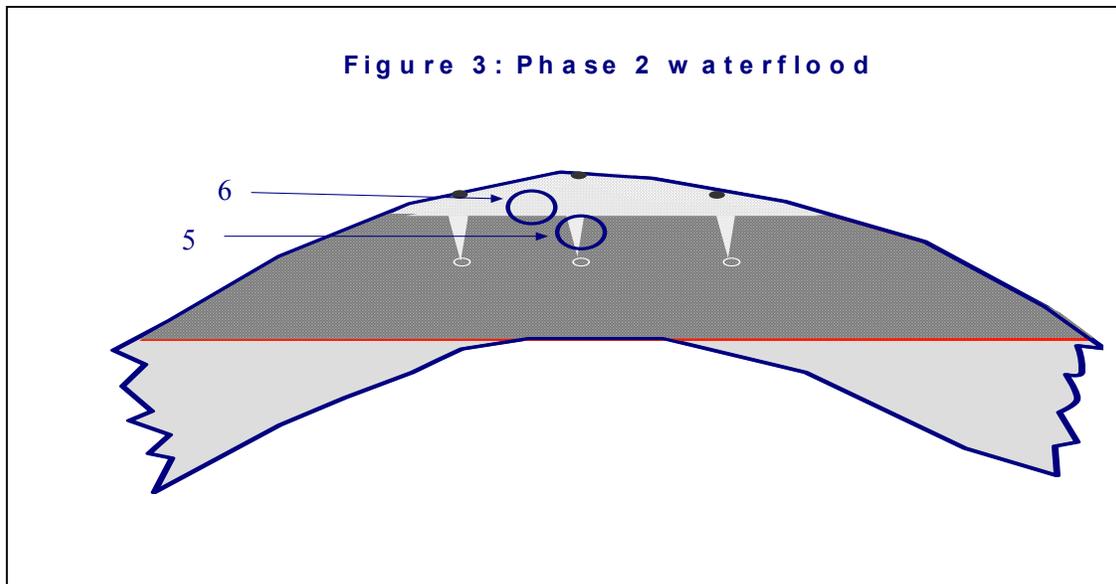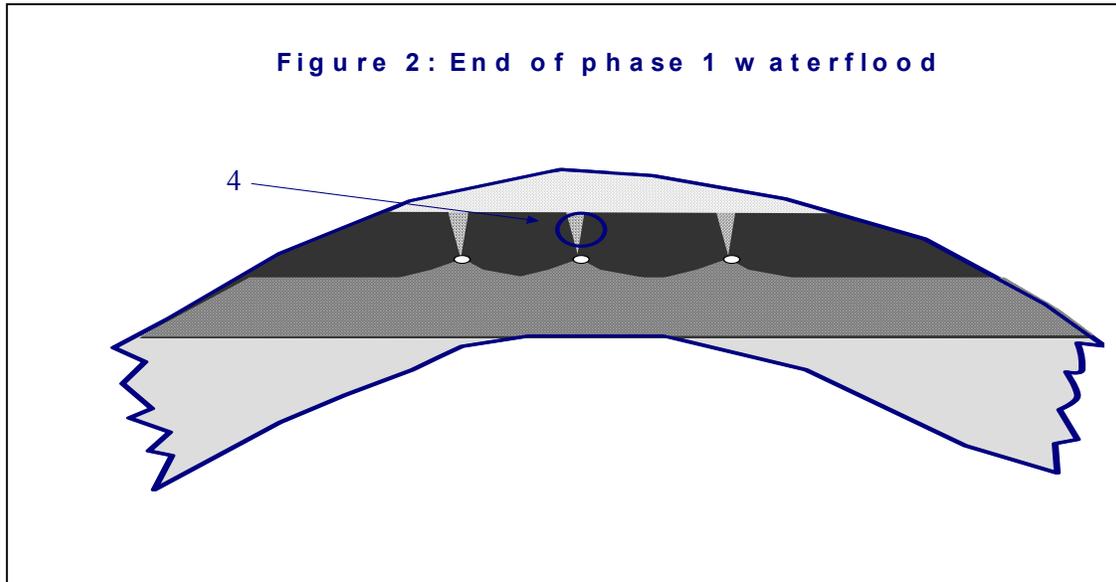
In Figure 3 a situation is represented where, later in field life, new producers have been drilled in the gas cap zone. Two more processes occur here which are similar to each other, except for the saturation history of previous processes. In region 5, a secondary water imbibition at trapped gas saturation occurs, following on from the secondary oil

imbibition described in Figure 2. In region 6, a secondary water imbibition at trapped gas saturation occurs, following on from the primary oil imbibition described in Figure 1. As can be seen a large number of relative permeability measurements would be required to fully replicate all the processes and all the saturation histories. Indeed it would be difficult in some cases to produce a meaningful measurement. To replicate all scenarios would result in a very large and expensive SCAL study that would not have represented value to the operator.

The key measurements with respect to the main target STOIP were assessed so that a focussed SCAL study could be defined that would provide the most benefit to the operator. In relation to the total reserves of the reservoir, the processes that occurred in the gas cone areas, i.e. in regions 2, 4 and 5, were considered to be of least importance. Also other uncertainties in the inflow performance and the fine grid necessary to correct model the areas would make prediction of the gas cone areas difficult. Key processes and therefore the most important measurements to be made were decided as:

- the water/oil imbibition – to describe the relative permeability and residual oil saturation in the main bulk of the reservoir (region 1)
- The oil relative permeability end point during the oil/gas primary imbibition and the measurement of S_{gt} (region 3). The trapped gas saturation to oil pushed into the gas cap during blowdown would be an important data point to support development decisions. The trapped gas saturation would define the maximum volume of oil that could be "lost" to the gas cap, a high value limiting the lost oil and vice versa. It would also indicate the volume of free gas to be produced. This would be a valuable data point even if new wells were not drilled in the gas cap. Should new wells be drilled in the gas cap later in field life, the S_{gt} would define the total target oil volume and the value of K_{ro} at S_{gt} would provide a measure of the maximum productivity of these wells.
- The water/oil secondary imbibition at trapped gas saturation (region 6). This data would describe the relative permeability and residual oil saturation in the gas cap region.

The above key measurements were therefore performed on samples of oil and gas leg core.

EXPERIMENTAL DETAILS

A previous study had been carried out for the same client on similar core in 1992. In that study water/oil relative permeability data had been measured on a number of composite cores, but the study did not benefit from in-situ saturation monitoring or core flood simulation. Consequently there was uncertainty in the measured relative permeability data as to whether it was affected by capillary pressure artefacts. The 1992 study concluded that end point oil recovery was rate dependent indicating significant capillary pressure effects. It was not clear however whether increased recovery with rate was due to mobilisation of oil held at the outlet of the core (by the capillary end effect) or whether increased rate mobilised oil throughout the length of the core (oil that would otherwise remain immobile), or both. Without a knowledge of this it is difficult to conclude whether the relative permeability data measured using reservoir advance rates were representative of the reservoir. The present study used gamma ray in-situ saturation monitoring (ISSM), so that the correct interpretation of the water floods and oil floods could be made, and core flood simulation to correct for capillary pressure effects if they were identified.

The relative permeability tests for the present study were carried out on separate oil leg and gas leg composite cores. The restoration technique was used, as opposed to preserved core, and water floods performed at reservoir advance rates and bumped rates. A novel core flood simulation technique [1] was used in conjunction with the in-situ saturation data to correct for capillary pressure end effects. The details of these processes are described below.

Core Preparation

Core plugs were received in sealed foil bags having been previously plunge cut from unconsolidated whole core. The plugs were held in heat shrink and the unconsolidated sand contained in the sleeve with a fine inner mesh and coarse outer mesh at each end. All samples were CT screened to identify the most homogeneous samples for the study. The plug samples were loaded into Hassler core holders for cleaning. As the core material was completely unconsolidated, the confining pressure on the core sleeve had a large effect on the permeability, with permeability decreasing with increasing confining pressure. This was studied in the 1992 project where it was concluded that a confining pressure of 1000psig gave stable and reproducible absolute permeability measurements. A 1000psig confining pressure was therefore adopted for the present study. The samples were flow through cleaned with alternate methanol and toluene flushes at 10bar back pressure and at 50ºC until the effluent ran clear. At no stage were the plugs dried. After the final methanol flush the plugs were brine saturated and their permeabilities measured over a range of rates from 50 to 500 ml/hr. Although the plugs had routine gas brine permeabilities of around 8000mD, the brine permeabilities for all plugs were measured at between 2200mD and 3500mD. On removal and inspection of the composites after cleaning, they were quite hard compared to their ambient state, from compaction by the confining pressure, and it was thought that this might have caused some reduction in permeability. However although no fines were seen in the effluent, a large build-up of

fines had occurred at each outlet fine mesh. Consequently, for further studies, the fine meshes were removed and replaced by 0.75mm meshes. Little further fines movement was seen and brine permeabilities measured later on the composite samples were back up to the expected 8000mD. Composite cores were made up of four cleaned, brine saturated plugs, ordering the plugs with the most permeable at the outlet to minimise capillary pressure end effects. The four plugs were held under slight compression whilst a Teflon sleeve was heat shrunk across all plugs to hold it as one unit. No capillary contact material was used between each plug, good capillary contact being provided by loose sand at each end face, the meshes having been removed from the inner faces. A 0.75mm mesh was fitted to each end of the composite. The absolute brine permeability of the oil leg composite was measured as 6833mD and porosity as 29.9%. The gas leg absolute permeability was 8786mD and porosity 31.4%. Porosity was measured by doped brine dispersion and ISSM techniques.

Conditioning of Composite Cores
The composites were flooded to S_{wi} with refined oil against porous plates. The displacements were monitored by ISSM to ensure uniform and target values were reached.

The composite was raised to reservoir conditions of 1356psig and 30.5ºC, preserving the 1000psi confining pressure during the process. The refined oil was replaced with live oil (with a dekalin buffer in between to prevent asphaltene deposition) and the effective permeability to live oil measured. The composites were then each aged for 3 weeks in total with the live oil replaced with 2 HCPV of fresh live oil each week during the ageing period. This was to ensure that molecular weight fractions in the live oil would be replenished to ensure full ageing. With no replacement of oil or if the sample is simply pressurised in oil (no flow through) there would be the possibility for a differential wettability profile down the core length. Also live oil was used (rather than dead oil) to ensure the correct solvency of the crude and therefore its correct wettability altering capacity. The live oil permeability was also monitored during ageing, the final values being 7077mD for the oil leg and 8746mD for the gas leg. S_{wi} measured by ISSM after ageing was 14.7%PV and 15.5%PV for the oil and gas legs respectively. Low, uniform values were achieved.

Core Floods
All core floods were performed without any depressurisation or movement of the core after the ageing period; they continued directly from the ageing process.   For all floods, production data, pressure drop data and in-situ saturations were measured at reservoir conditions.

Oil Leg Core
For the oil leg core, the water flood was performed at reservoir advance rates and the Peters and Flock criteria for the on-set of viscous fingering [2] were used as a guide to the maximum rate to use. The low rate flood was performed at 4ml/hr corresponding to

1.0ft/day total PV advance rate. This was estimated to give a stability number, N_s, of 9.5 for an intermediate wet core. This value of N_s, being lower than the critical stability number of 13.56 defined by Peters and Flock was expected to give a stable flood. The low rate flood was continued to a 99.9% water cut with no discontinuous flow within this period. The bump rate was then performed at 200ml/hr corresponding to 51ft/day and was continued for 25PV. The production data over the low and high rates are shown in Figure 4. The two curves show the recovery measured by volumetric (mass balance) measurements and by ISSM. The recovery as measured by ISSM was significantly greater than that measured by volumetric readings from the PVT cell. This effect has

Figure 4: Measured Oil Production - All Data Oil Leg
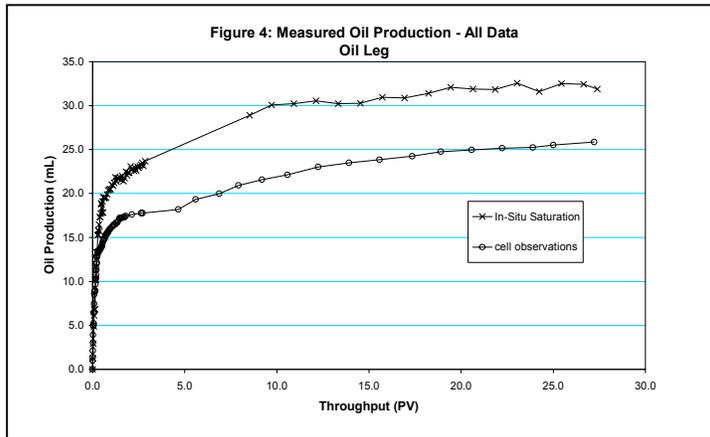
now been seen in a number of tests, not just the present study. It was concluded that the PVT cell data was incorrect as a proportion of the produced oil could be adhering to the dead volume pipework or could be trapped in dead legs of the rig pipework, thus not reaching the PVT cell and therefore not being quantified. We believe the effect may always occur to some extent, but was made more noticeable by the viscous nature of the test oil. Reliance on volumetric data alone would give an erroneously high residual oil saturation. Table 1 below shows the residual oil saturations by mass balance and ISSM methods. Quite significant differences occur, which in-turn could have a large influence on reservoir management decisions.

Table 1	Low rate flood	Sor (%PV)	High rate flood	Sor (%PV)
	ISSM	PVT Cell	ISSM	PVT Cell
oil leg	45.9	56.1	32.2	42.6

Figure 5: Low and High Rate End Point Saturation Profiles Oil Leg
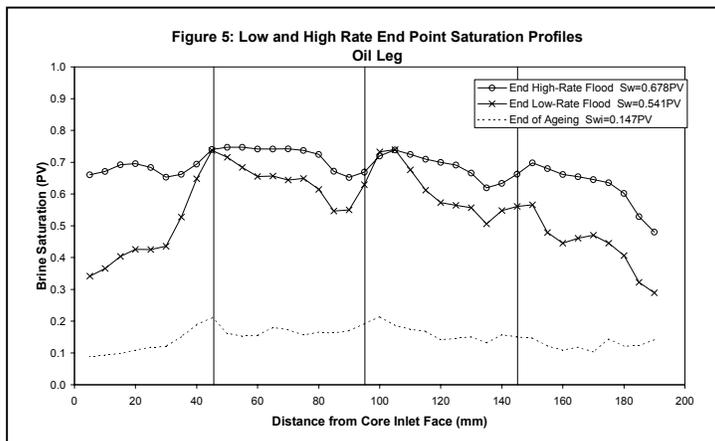
Another unusual result was seen in the endpoint saturation profiles shown in Figure 5. Here, the brine saturation of the inlet plug increases along its length, whereas it would be expected to be uniform or decrease along its length. This effect was explained as a viscous fingering phenomenon. The Peters and Flock criteria predicted a stable flood assuming an

intermediate wet core. However for an oil wet core $N_s = 258$ which would predict an unstable flood. Brine entered the core via the end platen orifice of approximately 1.5mm diameter. Even though the brine was spread over the core face by distribution grooves in the platen, water preferentially fingered through the middle of the inlet plug, gradually dispersing along its length. Thus the water saturation increases along the core length. This anomaly had implications for the core flood simulation, as it would be impossible to match saturations in the inlet plug. In this case the inlet plug was omitted from the simulation as described later.

As well as the inlet effect, there was a distinct hold up of oil at the core outlet after the low rate flood, see Figure 5. Oil was then subsequently produced from the outlet region and throughout the whole composite during the high rate bump. These two effects would be difficult to identify from mass balance data alone. Core flood simulation was used to account for this in the relative permeability analysis described later.

Both the anomalous inlet saturation effect and the increased recovery measured by ISSM compared with mass balance measurements were also noted in the operator's own in-house laboratories. These effects were seen during CT measurements made during a hot water flood of the same rock and fluid system as the present study.

Gas Leg Core

An oil flood to S_{gt} was performed prior to waterflood. To start with the correct core saturations after ageing, the live oil HCPV was replaced by humidified methane leaving no residual oil. This was achieved by miscibly displacing the live oil with pentane and then displacing pentane with methane at suitable miscibility conditions. The composite was then returned to test conditions. The live oil flood was then performed at 20ml/hr and gas production measured by volumetric measurements. This was expected to be a piston like displacement with oil acting as wetting phase and gas non-wetting. This was the case with no post breakthrough recovery being seen. The final S_{gt} was measured by ISSM and is shown in Figure 6. The value measured of 24.6%PV was slightly low because of a small degree of gas absorption at the inlet plug. The gas absorption was unavoidable as the live oil was equilibrated at bubble point, which was 34psi lower than test pressure and therefore the oil absorbed further gas at test conditions. The gas absorption could have been avoided if the flood was performed with fluids equilibrated at test conditions, but this would risk gas evolution during the flood which may have significantly affected the objective of the flood, namely the S_{gt}. However the ISSM data allows this artefact to be accounted for, giving the correct S_{gt} of 26.2%PV. This important result defines the oil that might be lost to the gas cap. S_{gt} measured by PVT measurements was 34.3%PV, erroneously high
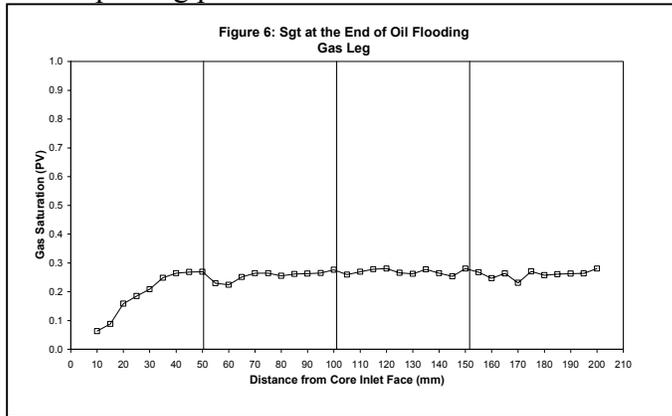
Figure 6: Sgt at the End of Oil Flooding Gas Leg

caused by gas absorption into the oil in the rig pipework and PVT cell. Again, this sort of laboratory artefact is avoided by using ISSM. Use of the correct data point here is important for reservoir development planning and the minimisation of the associated financial risk; the volumetric data point would suggest that less oil is lost to the gas cap than the ISSM data would. This in turn would suggest more oil is available in the present reservoir development and less oil would be produced from future development of the gas cap. The ISSM data point would suggest the opposite and is in our view the correct data.

The ISSM data of Figure 6 also confirms that there was no end effect at the cessation of the flood, providing confidence that the end point oil relative permeability was not artificially suppressed and was therefore representative of the reservoir. Low and high rate water floods were performed at S_{gt}. The low rate was performed at 4.4ml/hr corresponding to 1.0ft/day. This gave an Ns value of 7.4 which was expected to give a stable flood. The bump rate was performed at 220ml/hr corresponding to 50ft/day. The production data of these floods showed a similar discrepancy between mass balance and ISSM derived oil recoveries as the oil leg core. The low rate end point saturation profile is shown in Figure 7. The saturation profile shows a small end effect, which was later accounted for in the relative permeability analysis by core flood simulation.
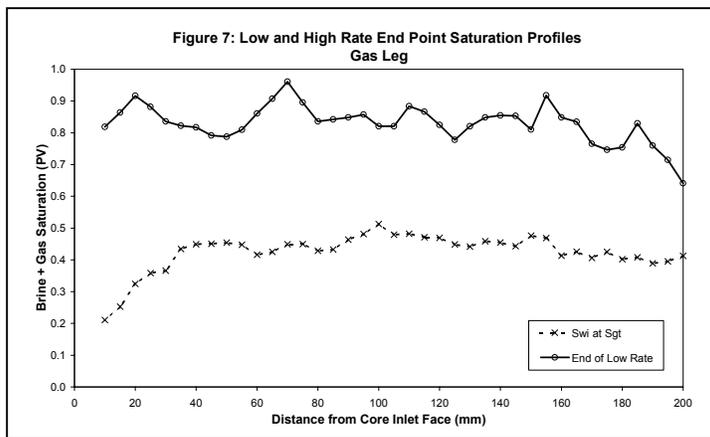
Figure 7: Low and High Rate End Point Saturation Profiles Gas Leg

Calibration of the ISSM Measurements

At the end of the water floods, the composites were flooded to 100%PV live oil and 100%PV doped brine saturations at test conditions. In addition, for the gas leg core, the following calibrations were obtained at test conditions:

- $S_o = (1-S_{wi})$ and $S_g = (1-S_{wi})$ – to derive oil and gas saturations during the oil flood
- $S_o = (1-S_{gt})$ and $S_w = (1-S_{gt})$ – to derive oil and brine saturations during the water flood at S_{gt}
- 100%PV humidified methane – to derive trapped gas saturation (in conjunction with oil and doped brine 100%PV calibrations)

Equilibrated methanol and toluene were used during the flooding sequences to achieve the above core saturations.

RELATIVE PERMEABILITY ANALYSIS

The pressure drop and production data was analysed by the JBN technique to derive relative permeability curves. It was recognised that the aforementioned capillary pressure effects would invalidate assumptions inherent in the JBN analysis and so the data was additionally analysed by core flood simulation.   The core flood simulation method was a novel technique that allows the relative permeabilities to be calculated without the need for an independent measure of capillary pressure, as is the case with conventional simulators. The independent measure of capillary pressure is normally from a different plug at different conditions to the water flood test and so is less likely to be representative of the sample used for water flood. The technique is described in detail elsewhere [1], but in summary the simulation is based on a de-coupled analysis of:

- pressure drop data to derive water mobility
- in-situ saturation data to derive oil fractional flow

Relative permeabilities are then evaluated from fractional flow and mobility functions.

Oil Leg Core

The relative permeability curves simulated for the oil leg core are shown in Figure 8.

Figure 8: Oil Leg Relative Permeability Data

Figure 9: Oil Leg Fit to Saturation Profiles
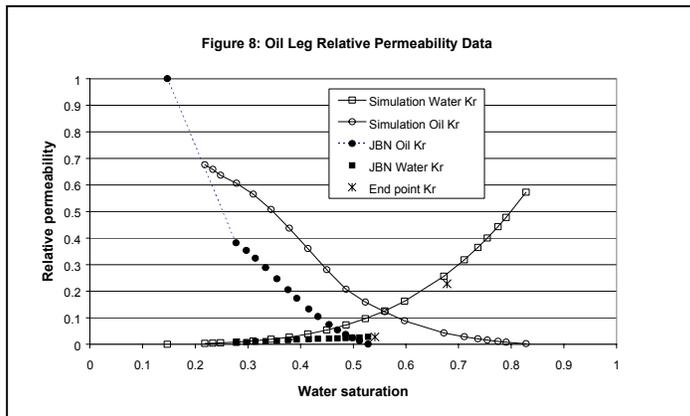
These are shown together with the relative permeability curves derived by JBN analysis. Significant differences between the JBN data and the simulated data are apparent which would have a marked effect on the production history of the reservoir. The JBN data shows suppressed low rate end point permeability, a steep upturn to the high rate end point permeability and a high S_{orw}, all characteristic of data affected by capillary pressure effects.   A number of simulated curves can be produced depending on the fit to the pressure drop and in-situ saturation profiles and the curves shown are the "best fit" example. A range of possible relative permeability curves was supplied to the client. The saturation profile fit for a
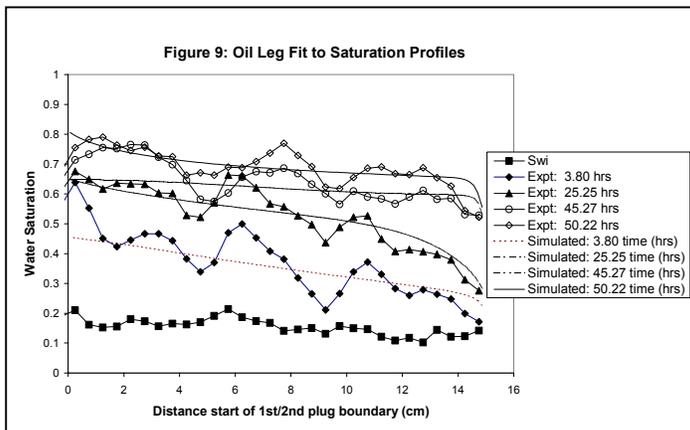
selection of low and high rate flood saturation profiles is shown in Figure 9.

Only the last three of the four plugs in the composite were modelled in the simulation because of the unusual water increasing saturation profile seen in the inlet plug (See Figure 5). The simulation technique allows individual sections of the composite to be separately modelled if required.

Figure 10: Oil Leg Differential Pressure Data

The pressure drop data used in the simulation is shown in Figure 10.

In the 1992 study a number of water floods were performed at the same reservoir conditions using similar high permeability unconsolidated core. Laboratory techniques were employed that, although were not identical, were similar to the present study, the main differences being that preserved core was used rather than restored and the composites were desaturated to S_{wi} by oil flood, rather than by flooding against a porous plate. Both low and high rate floods were performed, the low rates ranging from 0.3ft/day (flood 2) to 1.25ft/day (floods 1 and 3). The viscosity of the oil used was slightly higher than the present study at 133cp for flood 1 and 219cp for floods 2 and 3. However the fundamental difference of the 1992 study was, as mentioned previously, that it did not benefit from ISSM and core flood simulation. Consequently all the relative permeability data was analysed by JBN alone.

Figure 11: Oil Leg Core - Present and Historical Water Relative Permeability Data
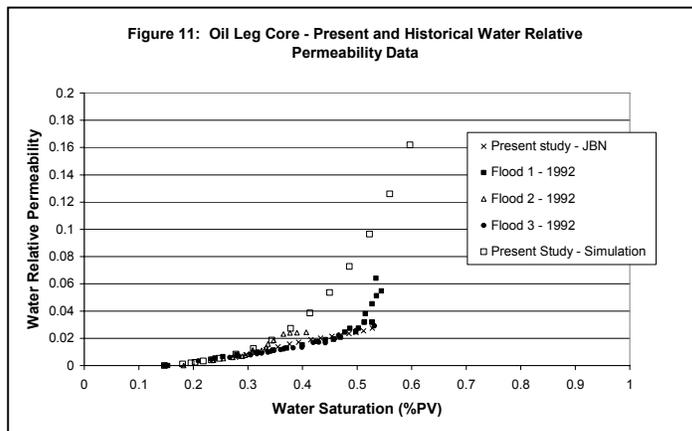
The 1992 data was revisited and compared to the data measured in the present study in order to clarify the validity of the earlier relative permeability data. Figure 11 shows the water relative permeability curves of the three measurements performed in 1992 together with the water relative permeabilities from the present oil leg core from both the JBN analysis and the simulation analysis. Apart from some small scale differences possibly attributable to water flood rate and fluid viscosities, it is quite apparent that the data analysed by JBN from both the previous study and the present study overlie each other, and are significantly lower than the simulation curve where end effects have been accounted for.

Figure 12: Oil Leg Core - Present and Historical Oil Relative Permeability Data
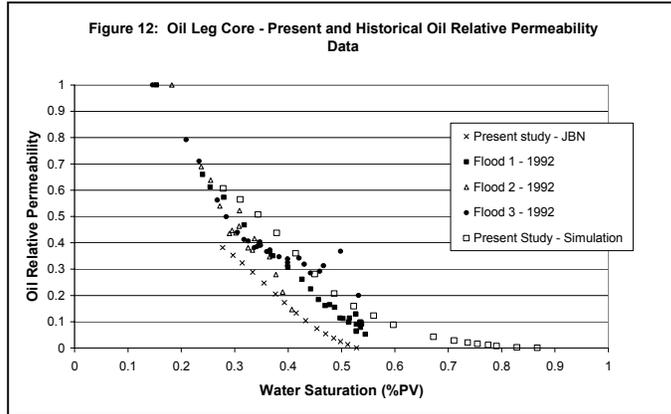
Therefore it can be concluded that the previous data was also end effected, rendering the low rate data unrepresentative of the reservoir. This was discussed in the 1992 report, but it could not be stated categorically at the time. The oil relative permeability curves were also compared. These are shown in Figure 12. The oil curves do not overlie each other, the curve from the present study being significantly lower than the previous study. Even within the data of the previous study there is more variation than the water curves. However, again all data seem suppressed compared to the simulated curve where capillary effects have been accounted for. The oil recovery with and without end effects are shown in Figure 13.

Figure 13: Oil Leg Core - Oil Recovery Curves
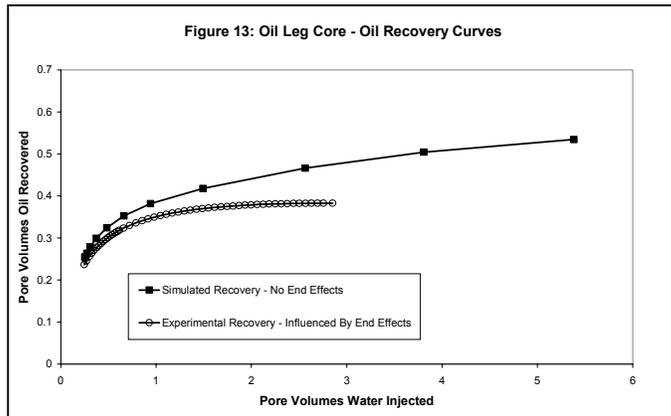
It would be interesting to compare recoveries seen in the field to those predicted from the SCAL data, but this data is not available at the time of writing. Figure 13 would suggest that significant differences between predicted recovery and actual recovery would be seen if the uncorrected relative permeability curves measured in 1992 were used in the reservoir simulation.

Gas Leg Core

The relative permeability of the oil imbibition into gas was measured as 0.34. The saturation profile shown in Figure 6 is evidence that no end effect occurred indicating the data point is representative of the reservoir. Should the operator drill in the gas cap, productivity would be based on a maximum permeability of 0.34 times that of the non-gas cap region.

Figure 14: Gas Leg Relative Permeability Data
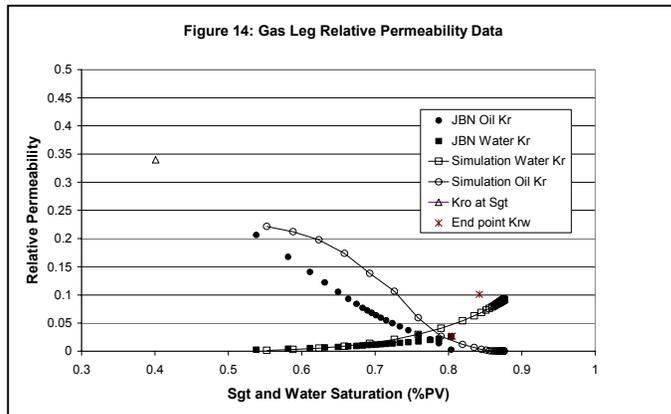
The relative permeability data from the water flood at S_{gt} was

analysed as for the oil leg core, by JBN first and then by simulation. The saturation

Figure 15: Gas Leg - Fit to Saturation Profiles
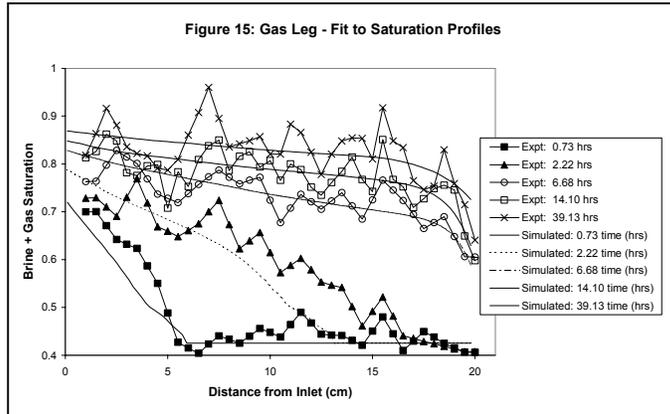
profile at the end of the low rate water flood, Figure 7, did not show a large end effect and so it was expected that the suppression of the water relative permeability would not be too great. The JBN and simulated relative permeability curves are shown in Figure 14. A difference is apparent but not as significant as for the oil leg. An example of the fit to a selection of saturation profiles measured during the flood is shown in Figure 15.

S_{orw} measured at the reservoir advance rate flood was 18% PV and this was taken as representative of the reservoir as the end effect was minimal, but may be even lower when corrected for the small end effect. The S_{orw} measured on the oil leg (i.e. with no trapped gas in place) at reservoir advance rate was 38%, after allowing for the end effects. The trapped gas saturation measured during the oil imbibition was 26%. A water flooding rule of thumb [3] states that S_{orw} with S_{gt} in place can be calculated by, at best, subtracting half the S_{gt} value from S_{orw} (with no gas in place), i.e:

$$S_{or\ (3\text{-phase})} = S_{orw} - 0.5S_{gt} \qquad (1)$$

The above equation was based on measurements in water-wet systems and reference [3] goes on to say that for intermediate wet systems evidence suggests that:

$$S_{or\ (3phase)} = S_{orw} \qquad (2)$$

for a range of trapped gas saturations. The present study indicates a system that is more favourable that that predicted by equation (1) which would give a lowest residual oil saturation of 25%PV. The measured value of 18% is significantly lower than this, providing an optimistic view of recovery in the gas cap region.

SUMMARY

This case study illustrates the benefits of integrating a proper reservoir engineering understanding of possible fluid movements, with the design of a core flood study. In this way, the key data requirements from the study can be defined, only the important measurements made and the reasons for not performing the less important measurements are understood. The client then benefits from a focused service providing key input data to the reservoir management process.

The case study also shows the importance of using best practice techniques, in-situ saturation monitoring and core flood simulation, to add confidence to SCAL data and thus reduce the risk in reservoir management decision making. Misleading data can be obtained if interpretation of core flood data is not undertaken with the utmost care and the use of these techniques is invaluable to the interpretation process.

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