GAS DISPLACEMENT EFFICIENCY FOR A LOW PERMEABILITY CARBONATE FIELD

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ABSTRACT

Miscible gas injection schemes are potentially attractive methods of improving oil recovery because they can result in lower residual oil saturations than water flooding alone. Gas injection may also access regions of attic oil bypassed by water flooding. Where there is no route to market associated gas, and environmental considerations prevent flaring, gas injection may also provide a means of managing excess gas early in field life. To achieve a horizontal displacement with gas injection, water may be injected in alternating slugs (WAG) to help control the high mobility of the gas.

Prediction of miscible gas injection performance, and comparison with water flooding, requires good quality relative permeability data. This paper describes the methods used, and presents the results of miscible gas displacement experiments which were performed at reservoir temperature and pressure using reservoir core material that was characterised and conditioned to provide initial oil saturations typical of reservoir conditions. Experiments were undertaken to investigate secondary miscible gas flooding, secondary water flood followed by tertiary miscible gas flooding and water alternating gas (WAG) floods.

The experiments were undertaken on a 52 cm long carbonate composite with an effective oil permeability of 1.66 mD. Test conditions for gas flooding were investigated just above the Minimum Miscibility Pressure (MMP) at reservoir temperature. The recovery from secondary miscible gas flooding, as one would expect, was high and resulted in very low residual oil saturation (S_{orm}). For the core material studied, water flood recovery (before tertiary gas flooding) was also good with high break-through recovery of oil. Tertiary miscible gas flooding resulted in additional oil recovery of 14%HCPV. Additional oil recoveries from two secondary WAG experiments (compared to secondary water flood) showed that recovery was proportional to the size of the initial gas slug. The measured laboratory data reduces the uncertainty in the planned field development options of this prolific reservoir.

INTRODUCTION

Field development options were studied to evaluate the optimum scenarios for the reservoir development plan. The initial strategy is to maximize plateau length and highest oil recovery for secondary rich gas, WAG, or tertiary WAG schemes within acceptable economic considerations. Five-spot pattern WAG injection using miscible gas was considered due to tightness of the reservoir, where average porosity and permeability were in the range of 16 % and 4 mD, respectively. The WAG development option has been optimized to develop this type of reservoir using horizontal producers and WAG injectors with 750 m spacing between producers and injectors. The oil recovery may be somewhat sensitive to the gas composition and minimum miscibility pressure (MMP). PVT studies indicated that the MMP was close to initial reservoir pressure so the simulation reservoir model pressure was designed to be above the MMP. Laboratory tests mimicking the field development options enhance the confidence in expected behaviour, and in many cases validate the model development. No previous data or tests were available on the gas process displacement efficiency of the presented study.

REVIEW OF THE LITERATURE

It is probably accepted by many in the Oil & Gas Industry that miscible gas displacement (and WAG schemes) are reasonably well understood and the development of Prudoe Bay in Alaska would be a good example of implementation. A Literature search was undertaken prior to this study revealing a plethora of papers. The monograph by Stalkup [1] provides an excellent overview on miscible gas displacement processes. The papers by Bardon et al. [2] and Tiffin & Yellig [3] provide insight into laboratory measurement techniques, handling of data and the importance of reservoir wettability. References on the effects of water injection, water blocking phenomena and optimum WAG ratio on miscible flooding were also identified [4, 5, 6, 7]. Many of the papers are related to CO_2 injection schemes and many are non-Field specific (i.e. using bead-pack or outcrop core and analogue fluids). Our motivation for this publication is the apparent correlation of oil recovery with initial gas slug size when undertaking a WAG displacement and to share data on a Field specific study undertaken at reservoir conditions with reservoir rock and fluids.

MEASUREMENT TECHNIQUES

Rig Description and Flooding Method

The facility used for this study was a reservoir condition rig contained within an oven and able to accommodate core samples of up to one metre in length. Two high pressure positive displacement pumps were used (one injecting fluids and one extracting fluids) in order to flood through the core at the required displacement rate. Typically a laboratory flow rate of 3 mL/h was used (corresponding to a typical reservoir advance rate of 1ft/day). For all displacements, the injection rate was kept constant with constant injection pressure. This required the need for small adjustments in the extraction rate to accommodate the changing flood characteristics as the original oil in place was produced.

The flood direction was always top to bottom (i.e. gas gravity stable), even when water flooding (secondary water flood and WAG).

For immiscible flooding (e.g. for core preparations and the secondary water flood), a long windowed PVT cell contained within the oven was used for volumetric data acquisition. A high pressure sampling station was used to collect fluids during post break-through miscible flooding. These high pressure samples were typically 10 mL to 15 mL in volume and were subsequently analysed in a PVT laboratory. The facility was equipped with numerous absolute pressure transducers, differential pressure transducers and thermocouples connected to a data logging system. A schematic of the facility is illustrated in Figure 1.

<u>Core Preparation</u>

Experiments were undertaken on one 52 cm long composite core (constructed from 10 core plugs of 3.8 cm diameter). The plugs were cut from preserved core samples and carefully chosen following CT imaging and measurement of effective brine permeability. Selected plugs were hot solvent cleaned (by a flow through technique) and established at 100% brine saturation. Individual plugs were desaturated to irreducible brine saturation (S_{wi}) using a flow through technique with a porous plate. In-situ saturation monitoring (ISSM) was also used to quantify S_{wi}. In addition, the pore volume and hydrocarbon pore volume was measured for the assembled composite using ISSM techniques. The composite core was aged at full reservoir conditions for a minimum of three weeks prior to core flooding. The reservoir oil was replaced each week with fresh fluid and the effective live oil permeability measured. The final permeability measurement was used as the reference permeability for defining relative permeability.

<u>Secondary Gas Flood</u>

The secondary gas flood was conducted at constant injection pressure at a flow rate of 3 mL/h (corresponding to a reservoir advance rate of 1ft/day). The injection rate was calculated directly from positive displacement pump injection volumes, which were density corrected from the laboratory (operating) temperature of 22°C to the test temperature. The required throughput was 1.5 PV which corresponded to 3 days of continuous core flooding (and sampling). For the first 24 hours of core flooding, the produced oil was measured at reservoir conditions using a long windowed PVT cell. After the 24 hour period (and before gas break-through), the produced fluids were diverted to a high pressure sampling station. High pressure, titanium sample tubes were changed on a cycle of 3-4 hours (6 hours towards the end of the test). The samples collected were subsequently flashed in a controlled PVT laboratory environment. In addition, all produced fluids (including rig pipeline dead volumes) collected in the PVT cell and outlet vessel were transferred to a 1 Litre sample vessel and this too was flashed in controlled conditions. At the end of the secondary gas flood and after removing produced fluids for analysis, the injection gas permeability was measured.

Tertiary Gas Flood

Following the secondary gas flood, the core was flushed with stock tank oil (STO) at full reservoir conditions. Given the low permeability and length of the composite, the STO could only be flooded at low rate, otherwise the pressure drop would have been excessive, potentially causing sleeve or core damage. STO flooding was continued to completely degas the composite. The STO was displaced with live oil and the effective permeability re-measured. A secondary water flood procedure was conducted at 3 mL/h for 2 PV throughput, which was considered representative of the field process. The flood performance was measured using observed PVT cell data at test conditions and making the necessary corrections for both oil dead volume and outlet dead volume (from the core outlet face to the PVT cell). Prior to tertiary gas flooding, all rig flow lines, PVT cell and outlet vessel were initialised with brine/water. Any incremental oil recovery measured during tertiary gas flooding would therefore be attributed to additional core production only. The flood procedure adopted was similar to the secondary gas flood. Initial production of brine was measured using the PVT cell. High pressure sampling commenced just before gas break-through.

Secondary WAG (Water Alternating Gas)

For the secondary WAG experiments, the core was initially returned to 100% formation brine saturation. This was achieved by first flushing dilute formation brine to degas the core, followed by methanol and toluene solvent cycles before re-flooding brine (at a reduced rig temperature of 60°C). The composite integrity following the cleaning process was established by measuring the absolute brine permeability. The composite was then flooded with STO and the brine production measured using the long windowed PVT cell positioned at the core outlet. The net brine production data was used to calculate S_{wi}. STO was displaced with live oil and the reference permeability at the new S_{wi} was measured. The composite was also re-aged for three weeks. As with previous gas flooding, the cell was initialised to minimise oil dead volume and the gas flood was conducted at constant injection pressure. Again, for the first 24 hours of core flooding, the produced oil was measured at reservoir conditions using a long windowed PVT cell. After the 24 hour period, the produced fluids were diverted to a high pressure sampling station. In addition the injection fluid was switched from gas to brine and back to gas, such that in total four cycles of each phase were injected (a total throughput of approximately 1.6 PV).

RESULTS

The study used a 52.0 cm long composite core and was measured to have a reference permeability of 1.66 mD at the test conditions 28 bar above the minimum miscibility pressure (MMP) at 129°C. The injection gas was considered to be a ‘rich’ gas (Table 1 at the end of this paper). The rock type porosity, permeability and pore size distribution may be found as ‘RRT1’ in reference [8].

Secondary Gas Flood Result:

The reservoir fluid used for the study had previously been analysed and the measured oil volume factor (B_o) was applied to the flashed volumetric data acquired from sampling to give the equivalent oil volume at the reservoir saturation pressure. Reservoir fluid density data was used to correct the fluid volume from the saturation pressure to the test pressure. From the measured gross oil volume, the rig oil dead volume was subtracted to derive the total recovery. The production data versus gas injection is presented in Figure 2. The data is presented as percentage hydrocarbon pore volume recovery (% HCPV) so that data between experiments (where S_{wi} may be different) can be compared directly. Gas break-through (BT) of 0.85 PV was determined from sample tube analysis. The miscible gas flood residual oil saturation (S_{orm}) was 0.04 PV (96 %HCPV recovery). The measured end-point gas relative permeability at S_{orm} was ~1. Results from compositional analysis are not covered in this paper.

Tertiary Gas Flood Results

Following the secondary gas flood, the core was re-established with live oil at S_{wi} (as described under the section Measurement Techniques). The effective oil permeability at S_{wi} was measured to be 1.58 mD which agreed remarkably with measurements undertaken prior to secondary gas flooding. It was therefore assumed that good composite integrity was maintained and that S_{wi} was also unchanged, enabling a direct comparison of the tertiary gas flood recovery with the secondary gas flood recovery.

A reservoir condition brine flood was conducted at a flow rate of 3 mL/h for a 2PV throughput prior to tertiary gas injection. Although the facility was equipped to flood in either direction; it was decided to flood vertically downwards for both the brine flood and the gas flood. If the brine flood was injected bottom to top (gravity stable), it would be unclear how capillary end-effect oil saturation might impact on the tertiary gas injection (injected top to bottom). Without in-situ saturation monitoring, the existence of end-effect is indeterminate, so the flood direction was kept fixed. The production data versus brine and gas injection are also presented in Figure 2 (for comparison with the secondary gas flood). The brine flood exhibited high break-through recovery and some post break-through drainage of oil. Break-through was at 0.65 PV (68 %HCPV recovery) and the remaining oil saturation was 0.25 PV (74 %HCPV recovery). The measured brine relative permeability at this saturation was 0.27.

The injection of 2 PV of tertiary gas immediately followed the secondary brine flood. Using the same analytical procedures as for the secondary gas flood, additional oil recovery was measured to be 14 %HCPV. Ultimately, the tertiary gas residual oil saturation was 0.12 PV (88 %HCPV recovery). The measured gas relative permeability was approximately 0.11 (S_g ~ 0.44 PV). As would be expected, gas displacing brine, break-through was early at 0.30 PV. The observed change in measured ΔP characteristic also provided confidence in measured volumetric data since it showed that the 'delayed' sampling data (due to outlet dead volume) was synchronised with the pressure data (which is ‘real time’). A summary of the secondary and tertiary gas displacement data are given in Table 2.

Secondary WAG Flood Results

For the first WAG experiment, gas flooding commenced at 3 mL/h for a throughput of 0.23 PV (flooding vertically downwards) before switching to brine injection. Following a brine throughput of 0.21 PV, injection was switched back to gas. The alternating gas and brine slugs after the initial gas slug were around 0.21 PV each (WAG ratio 1:1). Similarly for the second WAG experiment, the slug size was 0.21 PV except for the first gas slug which was increased to 0.50 PV. The oil recovery profile for each of the WAG experiments is shown in Figure 3, (together with the secondary gas and brine floods for comparison). These four secondary floods are also plotted in Figure 4 showing the overall recovery as a function of the size of the first gas slug (being 0 for the secondary water flood and 1 for the secondary gas flood). A summary of the secondary WAG displacement data is given in Table 3 at the end of this paper.

DISCUSSION

The measurements described in this paper were part of a much wider study, which included extensive reservoir condition oil-water relative permeability and wettability measurements, some of which is published [8]. The rock type used exhibits Amott-Harvey wettability indices of around –0.3 and USBM wettability indices of between –0.35 to –0.51. The Amott wettability indices to water observed on (four) samples were between 0.07-0.25 and the indices to oil were between 0.36-0.58. The rock type was considered to be intermediate to oil-wetting in character; but also showed some ability to spontaneously imbibe water as well as oil. The range of S_{wi} observed for this rock type was low (4%-15%) which is also indicative of oil-wetting core character.

For the comparison of production data, oil recovery is presented as hydrocarbon pore volume since S_{wi} for the secondary gas and secondary water floods were different from the later WAG floods. The recovery of oil versus gas injection for the secondary gas flood in Figure 2 shows that miscibility was achieved with recovery in excess of 90 % HCPV (at 1.2 HCPV throughput). Pre-breakthrough data indicated that the solubility of injection gas in reservoir oil was 8.5%. Break-through recovery was 83 %HCPV. This data confirmed that miscibility would be achieved using the associated injection gas at the test conditions cited. Following this initial test, the core was restored to a live oil saturation at S_{wi}. Given that the effective oil permeability was re-measured to be 1.58 mD (compared to 1.66 mD at the start of the study), S_{wi} was assumed unchanged and the restoration method validated.

The secondary water flood performance was as expected when compared to previously measured data on similar rock types [8]. The break-through recovery was high at 68 %HCPV (break-through occurred at 0.65 PV brine injected) which was a little surprising given that the character of the core is intermediate to oil-wetting. Late break-through (with little or no post break-through production) is a classical description of water-wetting core character. The very low S_{wi} acquired for this core (4.4% acquired using the porous plate method on individual core plugs) might be one reason for the apparent later break-through (which is expressed as a fraction of the PV injected), but otherwise the rock type might be showing some signs of mixed wettability characteristic. (Some spontaneous imbibition of water was evident during Amott wettability measurements). Post break-through drainage of oil was evident and the measured end-point brine relative permeability (at 2 PV throughput) was 0.27 again suggesting core characteristics indicative of intermediate to oil wet-wetting (consistent with the measured wettability indices). The recovery from the water flood was 74 %HCPV and the additional recovery from subsequent tertiary gas flooding was 14 %HCPV. The combined recovery of 88 %HCPV falls well below that of 96 %HCPV attained from secondary gas injection.

For the secondary WAG experiments it was necessary to re-initialise residual brine saturation (S_{wi}). Viscous oil drive (using STO) reduced the brine saturation to 9.9% and 10.1% respectively for the two experiments, which was fortuitous and allowed the two secondary WAG experiments to be compared directly. Recovery from WAG flooding is compared to the secondary gas and secondary water floods in Figure 3. Comparing the pre-break-through recovery profiles of the secondary water flood and secondary gas flood show directly the loss of recovery due to injection gas dissolution into the reservoir fluid. The oil recovery from WAG II (initial gas slug size 0.5 PV) was very similar to the secondary gas flood, but with earlier break-through resulting in lower overall recovery.

The secondary WAG I performance was only marginally better than the secondary water flood. At break-through, WAG I recovery was only 68 %HCPV (compared to 67 %HCPV for the water flood), although there was some post-break-through benefit from WAG I (ultimate recovery is ~5 %HCPV higher than the water flood alone). Figure 3 also shows that pre-break-through recovery is lower than both the secondary gas flood and WAG II. It is likely that the initial gas slug size is too small and given gas solubility (oil swelling) at the flood front, it is possible that the first brine slug has invaded the gas slug. This would result in a trapped gas saturation and earlier break-through of brine, thus reducing the effectiveness of the initial gas injection. Should the core also exhibit some spontaneous brine imbibition, injected water may imbibe into the gas zone also resulting in earlier break-through of brine and poorer displacement efficiency. The second injected gas slug is likely to invade the brine zone with early break-through (the results from the tertiary gas flood showed a gas break-through of 0.3 PV) and thus cause a relatively high remaining water saturation.

The results from tertiary gas injection and WAG flooding show the effects typical of water blocking, and the more water injected, the lower the recovery. Empirical correlations matching water blocking data have been presented in the literature, but this is not investigated in the current study. There is also a view that water trapping is much less severe or non-existent in oil-wetting porous media [3] although the result from our study suggest that this is not always the case. For effective recovery of additional oil by miscible gas injection (after water injection), the gas must first contact oil. In an intermediate to oil-wetting pore network, oil may be retained as oil film at the rock surfaces and/or in the smallest pores. In these areas, water may occupy the larger pores and (non-wetting) injection gas may well just displace water and vice-versa thus by-passing the target oil. The irreducible water saturation (S_{wr}) will effectively isolate the flowing gas phase from the oil. If the pore network exhibits mixed wettability, oil recovery might be expected to be quite effective in the water-wet regions, but this assumes of course that there is a significant residual oil saturation (which may not be the case if secondary recovery has been effective).

Figure 4 shows the oil recovery versus the WAG initial gas slug size (where 0 is taken as a water flood and 1 as a secondary gas flood). This plot was found to be linear and therefore for this rock type the relationship could be used to estimate oil recovery using larger (or smaller) initial gas slug size. For example, to reproduce the combined water flood and tertiary gas flood recovery of 88 %HCPV by WAG would require an initial gas slug size of around 0.62PV. For this study, apart from the first gas slug, the WAG ratio was kept constant at 1:1. This WAG ratio was specified by the Client, but it has been shown by previous authors that a WAG ratio of 1:1 may optimise recovery (particularly for oil-wetting core). Jackson et al. [5] report that the wetting state is a major factor affecting flood performance and that maximum recovery is a stronger function of slug size in secondary mode than tertiary flooding (CO_2 injection on bead-pack).

Compositional and core flood simulation techniques are being used to model laboratory data and validate the equation of state and relative permeability curves that could be used in a full field model to simulate gas injection and WAG displacement processes. This work may be the subject of a future publication.

CONCLUSIONS

The laboratory miscible gas process displacement efficiency experiments demonstrated that good recovery can be achieved at realistic gas injection volumes on carbonate reservoir core. For the secondary gas flood, core flood miscibility was demonstrated for associated rich gas just above the minimum miscibility pressure with a recovery in excess of 90 % HCPV achieved with 1.2 HCPV throughput.

The recovery from a secondary water flood was 74 %HCPV (after 2 PV throughput) and was consistent with water flood characteristics measured on single reservoir core plugs of the same reservoir rock type. This reproducibility of data enhances the confidence of laboratory acquired water flood data using both long composites and short plugs when performed with due care and diligence. The high secondary recovery observed is consistent with intermediate wettability reservoir cores, which had been verified for the rock type under investigation by independent Amott wettability tests. The tertiary gas flood performance was an additional recovery of 14 %HCPV (a combined water flood and tertiary gas flood recovery of 88 %HCPV). The results indicated possible water blocking effects, which were not expected for this intermediate to oil-wetting rock type.

Closer examination may be required since water blocking is likely to have potential consequences on the field development strategy.

The results from the four secondary displacements indicated that recovery was directly proportional to the size of the initial gas slug. This relationship confirms the existence of trapping mechanisms which may lead to different ultimate recoveries for this intermediate to oil-wetting carbonate field. The observed relationship also shows that the WAG data are consistent with observed recoveries from secondary gas and water injections, provided that normalised recovery is plotted (%HCPV) to allow for the experimental variations in the initial water saturation (S_{wi}). It would appear that the optimum recovery would be achieved by a WAG flood using a high initial gas slug size, to emulate the recovery of a secondary gas flood followed by water injection. For the application of this experimental data in field modelling, there are up scaling issues to be addressed. The inherently unfavourable gas-oil mobility ratio will impact on field recovery, although at the laboratory scale (using 1-dimensional core) recoveries proved to be very favourable.

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TABLES

TABLE 1: Synthetic Injection Gas Composition

Component	Mol.%
N_2	0.71
CO_2	4.43
C1	75.47
C2	8.81
C3	5.45
iC4	1.20
nC4	2.20
iC5	0.62
nC5	0.60
C6	0.37
C7	0.13
C8	0.01

TABLE 2: Comparison of Reservoir Condition Core Floods

	Secondary Gas Flood	Secondary Water Flood	Tertiary Gas Flood
Initial Oil Saturation, S_{oi} *(PV)*	0.95	0.95	0.25
Gas/Water Injected at Break-through (*PV*)	0.85	0.65	0.30
Oil Recovery at BT (*%HCPV*)	83%	68%	0%
Oil Recovery (*%HCPV after 2PV Injection*)	96%	74%	14%
End-point Oil Saturation, ***Sor*** *(PV)*	0.04	0.25	0.12
k_{rg} *(or* k_{rw} *as appropriate)*	1.00	0.27	0.11

TABLE 3: Comparison of Reservoir Condition WAG Core Floods

	Secondary WAG I Flood	Secondary WAG II Flood
Initial Oil Saturation, S_{oi} *(PV)*	0.90	0.90
First Gas Slug Size *(PV)*	0.23	0.50
WAG Ratio	0.21	0.21
Gas/Water Injected at Break-through (*PV*)	0.70	0.72
Oil Recovery at BT (*%HCPV*)	67%	75%
Oil Recovery (*%HCPV after 2PV Injection*)	79%	85%
End-point Saturation, ***Sor*** *(PV)*	0.19	0.14

FIGURES

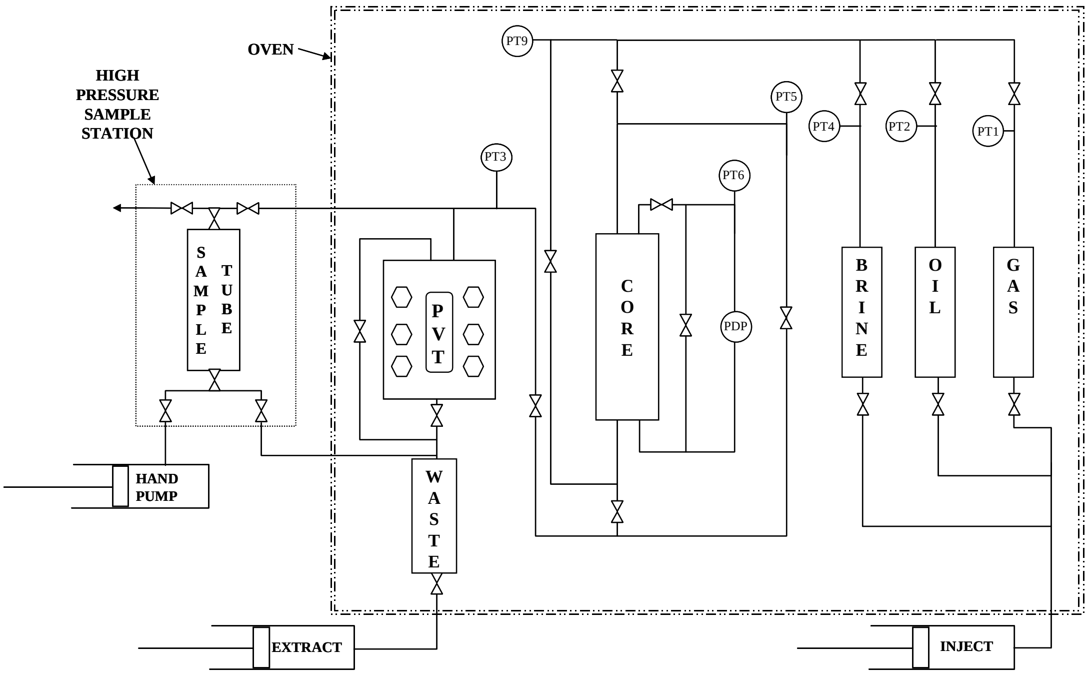

FIGURE 1: Schematic of the Reservoir Condition Facility

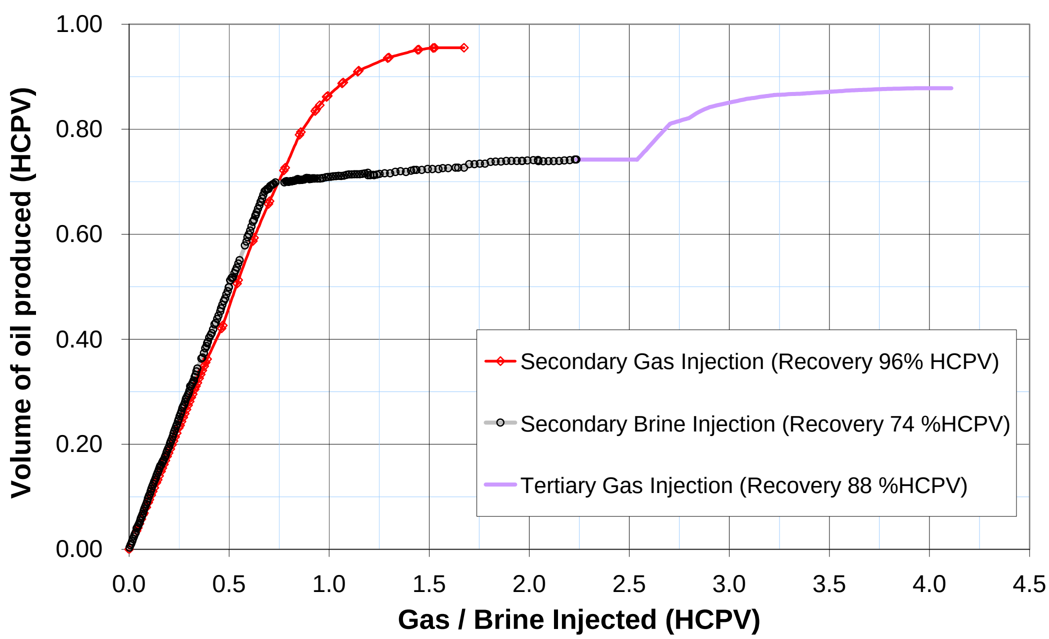

FIGURE 2: Oil Recovery from Secondary & Tertiary Gas Injection (HCPV)

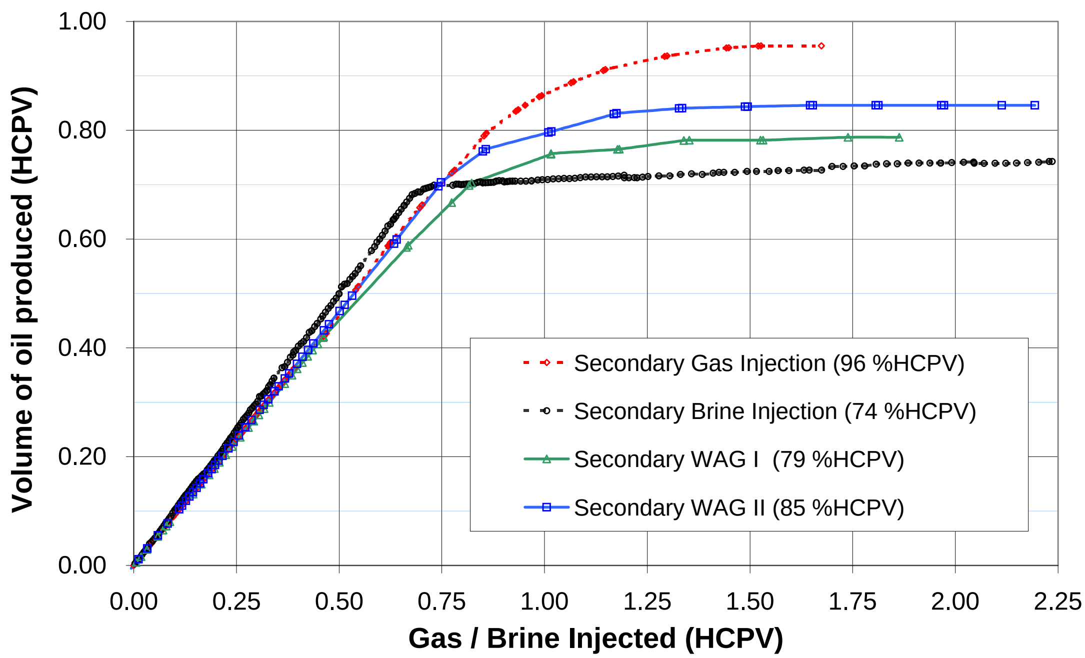

FIGURE 3: Recovery Profile from Secondary Displacement Processes

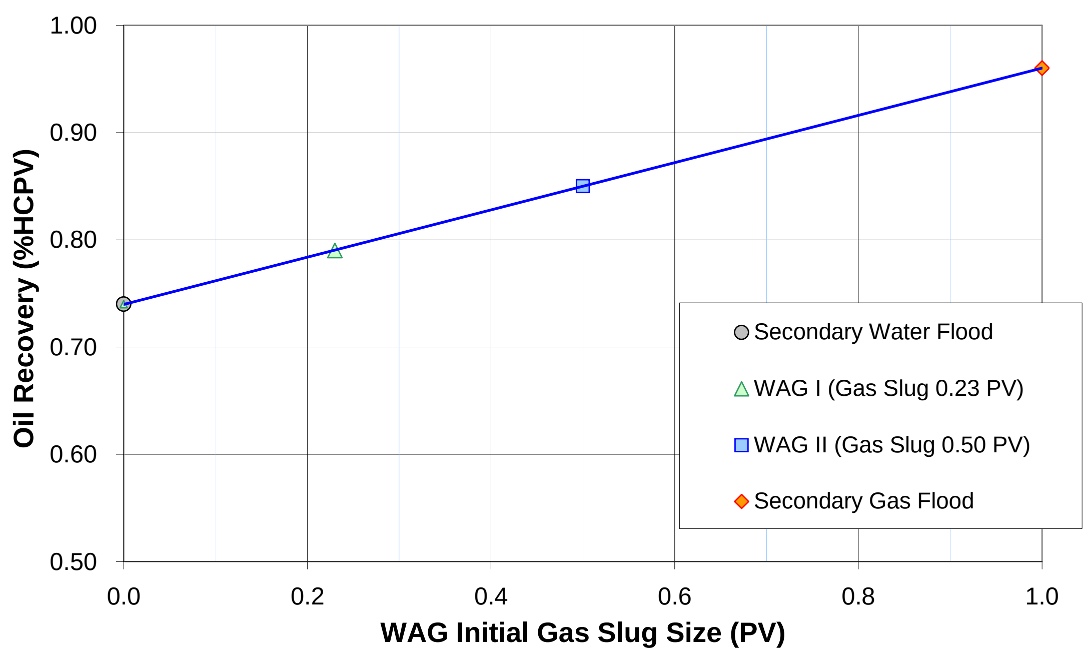

FIGURE 4: Oil Recovery Versus Initial Gas Slug Size