Improvement of Sweep Efficiency in Gas Flooding

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Abstract

Miscible and near-miscible gasflooding has proven to be one of the few cost effective enhance oil recovery techniques in the past twenty years. The sweep efficiency of such processes is often not high because of the adverse viscosity ratio and density difference between the solvent gas and the oil as well as the reservoir heterogeneity. Water-alternating-gas processes are often used to improve sweep efficiency. Foams and direct thickeners have been developed, but not used in field routinely. Effect of new well architectures on sweep efficiency is poorly understood. As the scope of miscible flooding is being expanded to medium viscosity oils in shallow sands in Alaska and shallower reservoirs in the lower 48, there are questions about sweep efficiency in near-miscible regions. The goal of this research is to evaluate sweep efficiency of various miscible processes in a laboratory model and develop numerical tools to estimate them in fields. In the last year, a high pressure quarter 5-spot model was assembled. We conducted slim tube tests, corefloods, and quarter 5-spot floods with an Alaskan shallow sands oil. We developed 1D compositional models of core floods and streamline-based compositional model of quart 5-spot WAG floods. Plans for the next six months include experimental quarter five-spot gas/WAG floods, and 3D modeling of these experiments.

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Executive Summary

Miscible and near-miscible gasflooding has proven to be one of the few cost effective enhance oil recovery techniques in the past twenty years. The sweep efficiency of such processes is often not high because of the adverse viscosity ratio and density difference between the solvent gas and the oil as well as the reservoir heterogeneity. Water-alternating-gas processes are often used to improve sweep efficiency. Foams and direct thickeners have been developed, but not used in field routinely. Effect of new well architectures on sweep efficiency is poorly understood. As the scope of miscible flooding is being expanded to medium viscosity oils in shallow sands in Alaska and shallower reservoirs in the lower 48, there are questions about sweep efficiency in near-miscible regions. The goal of this research is to evaluate sweep efficiency of various miscible processes in a laboratory model and develop numerical tools to estimate them in fields. In the last year, a high pressure quarter 5-spot model was assembled. We conducted slim tube tests, corefloods, and quarter 5-spot floods with an Alaskan shallow sands oil. We developed 1D compositional models of core floods and streamline-based compositional model of quart 5-spot WAG floods. Plans for the next six months include experimental quarter five-spot gas/WAG floods, and 3D modeling of these experiments.

Introduction

Miscible gas flooding has proven to be one of the few cost effective enhance oil recovery techniques in the past twenty years. There are about 80 gasflooding projects (CO_2, flue gas and hydrocarbon gas) in US and about 300,000 b/d is produced from gas flooding. Many of these projects are cost effective even in the low oil price scenario (~18$/bbl). However, the recovery efficiency is low (10-20% OOIP). Solvent utilization is also low (3-12 MCF/bbl). The primary reasons for this low efficiency are adverse viscosity ratio, adverse density difference, and the reservoir heterogeneity. Water-alternating-gas processes are often used to improve sweep efficiency. Foams and direct thickeners have been developed, but are not used in field routinely.

One of the problems in commercializing sweep improvement techniques is the evaluation of sweep efficiency. Reservoir condition laboratory tests such as corefloods and slimtube tests do not evaluate sweep efficiency. Field-scale evaluation of any new technique is very expensive and results are often inconclusive. Field-scale modeling of compositionally complex processes is often unreliable due to inaccurate representation of heterogeneity and process complexity. Reservoir condition laboratory tests need to be developed and field-scale compositional modeling needs to be improved to evaluate sweep efficiency. The purpose of this work is to evaluate sweep efficiency of various miscible flooding processes in a laboratory model, develop numerical tools to estimate sweep efficiency in the field-scale and identify solvent composition, mobility control method and well architecture that improve sweep efficiency.

This report summarizes our results for the period of October 2004 through March 2005. The notice of award was executed on November 29, 2004. The three tasks for the project are: (1) Solvent composition, (2) Sweep efficiency, and (3) Numerical model. Work was done on all the tasks in this quarter; the activities are described in the next section.

Approach

Oil. Two crude oils are used in this work: Oil A and Oil B. Oil A was prepared in our laboratory by adding methane to a dead reservoir oil for a live oil viscosity of about 50 cp. It was used for corefloods. Oil B was a dead reservoir oil of viscosity 78 cp. This oil is used for the 5-spot studies because we ran out of oil A. The two reservoirs are close to each other.

Component	Mol %
CO2	6.09
C1	38.29
C2	3.12
C3	3.76
C4	22.24
C5	12.88
C6	3.10
C7	3.10
C8	3.71
C10	3.71

Table 1 – Composition of solvent 1

Solvent. Two solvents were used in this work. Solvent 1 was prepared in such a way that its composition is the same as an equimolar mixture of an NGL (natural gas liquid) and a lean gas (LG). The composition of the solvent is shown in Table 1. Solvent 2 was pure ethane. It is multicontact miscible with oil B at the operating conditions.

Slimtube. Slimtube studies were conducted in a 20 ft long slimtube for oil B with solvent 2. The pressure was varied from 1000 to 1500 psi. The slimtube studies for oil A and solvent 1 have been conducted elsewhere.

Coreflood. A Berea core was used to perform linear WAG floods. The core had a porosity of about 18% and a permeability of about 116 mD. The core properties are shown in Table 2. The experimental apparatus is shown in **Fig. 1**. The Berea core had a residual water saturation of 28.6%. It was flooded with the live oil at a constant flow rate of 9 ml/hr until reaching a steady state. The solvent or water-alternating-gas slugs were then injected into the core at the same rate. Pressure drop and effluent composition were monitored. Oil A and solvent 1 were used in these experiments.

Core				
	D (cm)	5.050	A (cm^2)	20.03
	L (cm)	25.100	V (cm^3)	502.74
N2	K (md)	386.59	V_p (cm^3)	91.00
Brine	K (md)	116.34	ϕ	18.10

Table 2 – Properties of the Berea core.

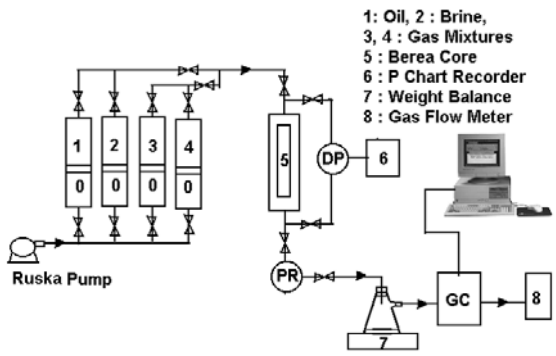

Fig. 1 – Experimental apparatus used in WAG floods

Quarter 5-Spot Model. A quarter 5-spot high-pressure cell was built to mimic the areal sweep of an oil reservoir. The 5-spot high-pressure cell consists of three stainless steel circular plates.

The top and bottom plates are identical. Each has a cut-in section for the overburden liquid. The middle plate has a cut-off section of 10” x 10” x 1” at the center for the porous medium. Two circular sheets of rubber are used to sandwich the packing and prevent bypassing when liquid is flowing through the medium. The other side of the rubber faces the overburden liquid when the three plates are put together; an overburden pressure of 2000 psi is applied. The porosity is 30.5%; the oil permeability is about 5 darcy at the connate water saturation.

There are 12 ports for various well configurations and to distribute the oil effectively at the beginning of each experimental run. There are 5 ports each on two opposite sides (A1-A5 and B1-B5) and two ports at the other two corners. For vertical well configuration, the solvent is injected at port A1 and the production is collected at port B1 while other ports are shut. For vertical injection and horizontal production wells, the fluid is injected at port A1 and the production is collected at ports B1 - B5. The maximum safe operating pressure for the porous section is about 2000 psi while the overburden pressure is maintained at 2500 psi. The cell is then hooked up to the flow loop and WAG floods are conducted. The flow rate was maintained at 22.5 ml/hr during gas and WAG floods. The BPR pressure was approximately 1350 psi. Oil B and solvent 2 were used in these experiments.

Results and Discussion

Slimtube. The slim tube was charged with oil B and displaced with solvent 2 at various pressures. The oil recovery is shown in **Fig. 2**. It should be noted that above 1340 psi, the oil recovery at 1.2 PVI is greater than 98%. The effluent from the slimtube (before the BPR) was observed in a high-pressure visual cell in the experiment at 1340 psi; multiphase flow was observed for a short time. Thus solvent 2 can be considered to be multi-contact miscible at 1340 psi.

Corefloods. The Berea core was flooded with oil A at a steady flow of 9 ml/hr. Then gas (solvent 1) was injected into the core at the same rate after oil injection. 0.6 PV of solvent 1 was injected followed by water. The composition of the injection solvent is listed in Table 1; it is an equimolar mixture of NGL and LG. This solvent is multicontact miscible at the core pressure according to previous slimtube studies.[25] The pressure drop across the core as the function of gas injection is shown in **Fig. 3**. Pressure drop decreases sharply as the gas breaks through the core. The final pressure drop is very small indicating that there is no injectivity problem associated with the solvent injection.

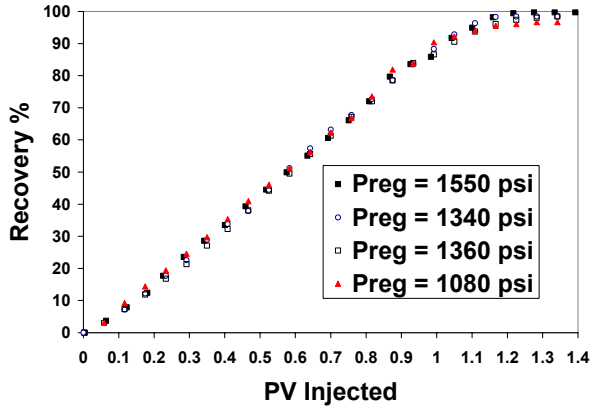

Fig. 2 - Oil production in slimtube displacements

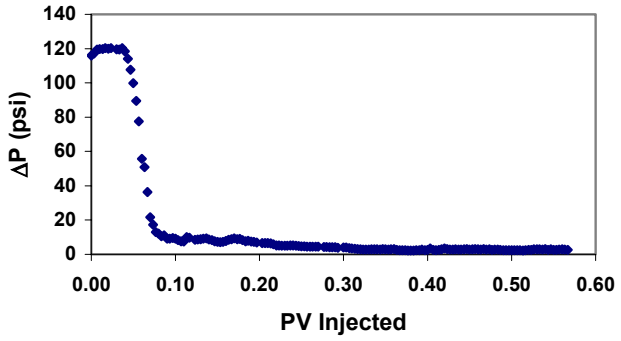

Fig. 3 – Pressure drop during gas injection

The cumulative oil production as a function of gas injection is shown in **Fig. 4** (along with the results from WAG injections). Oil production rate falls after about 0.25 PV injection of solvent indicating breakthrough of solvent. The cumulative production of oil at the end of solvent injection is about 45% of the original oil. Water injection was continued for another 1.4 PV and the final recovery is about 67% OOIP.

In 1D (slimtube) displacement of oil by this multicontact miscible solvent, the recovery is often greater than 95%. The existence of a residual oil of 33% in the coreflood implies bypassing in the core leading to immiscibility development and residual oil trapping. This miscible flood in the core is not hydrodynamically stable because of adverse mobility ratio. This adverse mobility and core-scale heterogeneity lead to bypassing. Bypassing can lead to immiscibility development and residual oil trapping. In addition, the waterflood after the gasflood displaces the gas from the gasflooded region; a part of the originally bypassed region never contacts the solvent. Thus the oil recovery is low. Water-alternating-gas slugs were injected in the following experiments to minimize bypassing.

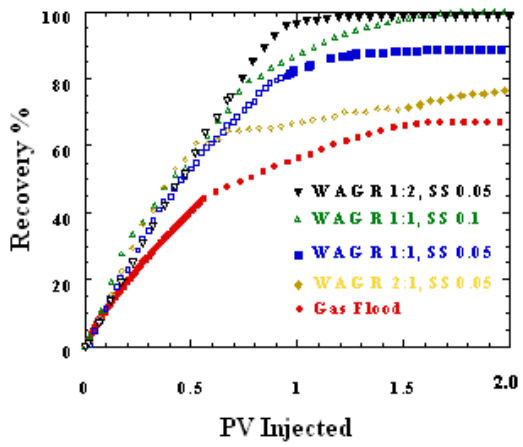

Fig. 4 – Cumulative oil production vs. PV gas injection

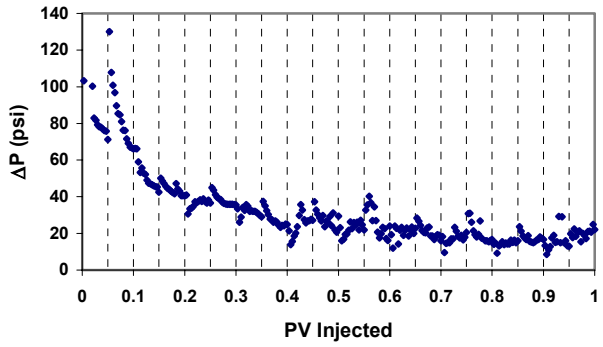

Fig. 5 – Pressure drop for WAG ratio =1 flood, slug size = 0.05 PV.

The WAG ratio of 1 with the slug size of 0.05 PV was used in the second experiment. About 0.5 PV of total solvent was injected. About 0.5 PV of brine was injected alternating with the gas slugs followed by another 1 PV of water. The pressure drop versus cumulative injection is shown in **Fig. 5**. Every time a gas slug is injected, the pressure drop decreases because gas is

less viscous than oil or water. Every time a brine slug is injected, the pressure drop first increases and then decreases because of relative permeability effects.

The cumulative oil production is shown in Fig. 4. The oil production rate is about constant until about 0.35 PV injection. The oil production rate falls after 0.35 PV injection, but not as much as in the gas flood. Water production increases after 0.35 PV injection. With the WAG ratio 1:1, about 80% of oil was recovered by the end of the end of the WAG injection (i.e., 1 PV). By the end of the follow-up water injection (2 PV total injection), the oil recovery was 88%. This experiment shows that WAG injection stabilizes the displacement at the core-scale and gives recovery similar to 1D slimtube floods.

WAG ratio of 1 with the slug size of 0.1 PV was used in the next experiment. After 0.1 PV gas injection, 0.1 PV of brine was injected at the same flow rate. The procedure was repeated with gas and brine injection until a total 0.5 pore volume of gas was injected into the core. This was followed up with a brine injection for a total of 2 PV of gas and brine injection. The oil recovery is almost 100% OOIP in this experiment.

WAG ratio of 2 with the slug size of 0.05 pore volume was used in the following experiment. The experiment started with 0.05 PV of gas injection followed by 0.1 PV of brine. The total of 0.5 PV of gas mixture was injected into the core in this experiment. The oil recovery is about 77% OOIP.

An additional linear WAG flood with a slug size of 0.05 PV and a WAG ratio of 0.5 was conducted. The oil recovery is about 100% in this WAG flood. Fig. 4 shows the comparison in percentage oil recovery for gasflood with different WAG floods. As the WAG ratio increases, the oil recovery increases for WAG ratio 0 to 0.5, but then decreases from 0.5 to 2. Thus, the optimum WAG ratio for this core is about 0.5 in this linear core geometry. The oil recovery increases with the slug size at a constant WAG ratio.

5-Spot Gasflood. The quarter 5-spot model was initially saturated with water and the oil was injected. The residual water saturation was determined to be ~9 % in this cell. The injection flow rate was 22.5 ml/hr for oil, solvent and water. The back pressure regulator pressure was set at 1350 psi. Two gas flood experiments were conducted, one with a horizontal production well and the other with a vertical production well. The injection well was a vertical well in both the cases. The injection rate of gas was constant at 22.5 ml/hr. The length of the horizontal well was equal to half of the side of the quarter 5-spot.

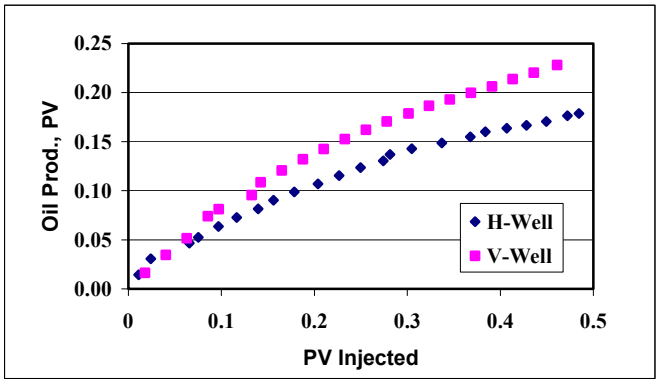

Fig. 6 – Oil recovery during gas injection in the quarter 5-spot model

Fig. 6 shows the oil recovery as a function of solvent and water injection. The breakthrough of the solvent occurred in the horizontal well case at about 7% PVI. The oil recovery at 45% PV solvent injection was about 17% PV. In comparison, the solvent breakthrough occurred at about 8% PVI for the vertical production well case. The recovery at 45% PV solvent injection was about 22.5%, significantly larger. Horizontal wells can lower the breakthrough sweep efficiency by providing a shorter path between the injection and production wells. Horizontal wells, however, do increase well productivity. In these experiments the injection rate was kept constant; the pressure drop was lower in the case of the horizontal well.

The viscosity of the separator oil (after the BPR) was analyzed; viscosity decreases after breakthrough and then increases indicating multicontact miscibility.

Fig. 7 shows the gas production from the 5-spot during gas injection; the produced gas volume is at the atmospheric condition. The breakthrough of the gas for the horizontal production well is just a little bit ahead for the vertical production well. The gas production for the horizontal well is significantly higher during the latter part of the gas flood.

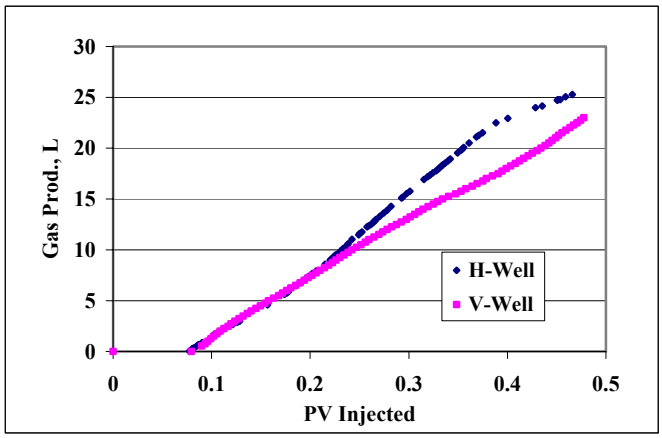

Fig. 7– Gas production during gas injection in the quarter 5-spot model

5-Spot WAG Flood. The quarter 5-spot model was flooded with oil to bring it back to residual water saturation (of about 9%) after each experiment. All the solvent dissolved in the oil and was removed from the core. A vertical production well was used in all WAG floods. At the beginning of the WAG experiments slugs of solvent and water were injected alternately until 0.5 PV of solvent was injected, after which water was injected continuously until a total injection of 2 PV. The injection flow rate was 22.5 ml/hr for solvent and water. The back pressure regulator pressure was set at 1350 psi. Two WAG flood experiments were conducted, one with a slug size of 0.05 PV and the other with 0.01 PV. The WAG ratio was 1. The production well was vertical in these experiments. The gasflood experiment described in the last section with a vertical well

was followed up with water injection for a total injection of 2 PV. This experiment can be considered as a WAG experiment with the WAG ratio = 0.

Fig. 8 shows the oil production in the WAG experiments and the gas flood experiment followed by water injection. For each experiment, the oil production has two parts. The first part is called WAG flood or gas flood in the figure caption. The second part is called the waterflood; this corresponds to oil production during the waterflood following the WAG or gas floods. For the WAG injection (WAG ratio = 1) with slug size (SS) 0.01 PV, the oil recovery is about 0.68 PV. About 0.56 PV of oil is produced during the WAG injection, which corresponds to a total fluid injection of 1 PV. After the water injection, the oil production rate decreases, but oil continues to be produced even at the 2 PV total injection when the experiment is stopped. The total oil recovery is 75% OOIP. This high recovery is possible because the medium is almost homogeneous, ethane is a MCM solvent and it reduces the oil viscosity substantially.

For the WAG injection (WAG ratio = 1) with slug size (SS) 0.05 PV, the oil recovery is about 0.61 PV. About 0.50 PV of oil is produced during the WAG injection, which corresponds to a total fluid injection of 1 PV. About 0.11 PV of oil is produced during the post-WAG water injection. The total oil recovery is 67% OOIP. Comparison of the last two experiments implies that as the slug size decreases from 0.05 PV to 0.01 PV, the oil recovery (and thus sweep) increases. This due to the fact that smaller slug size gives rise to better mixing of the solvent and the oil. Injection of the solvent slugs forms small fingers into the oil and the following water slugs push these solvent fingers into the oil. Larger slug size forms larger solvent fingers, which lead to less mixing of oil and solvent.

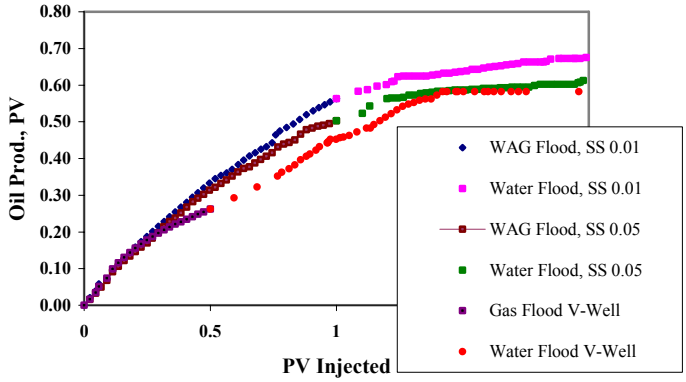

Fig. 8 - Oil recovery during WAG injection in the quarter 5-spot model

For the gas flood (WAG ratio = 0) followed by waterflood, the oil recovery is about 0.58 PV. About 0.26 PV of oil is produced during the gas injection, which corresponds to a total fluid injection of 0.5 PV. About 0.32 PV of oil is produced during the post-gasflood water injection. In fact the rate of oil recovery increases during the waterflood compared to the end of gasflood. Water injection following the gas injection mixes the solvent with the oil, lowers its viscosity and water can displace this lower viscosity oil more efficiently. The total oil recovery is 64% OOIP. Comparison of this experiment with the first WAG experiment implies that as the WAG ratio increases from 0 to 1, the oil recovery increases. Water alternating gas slugs mix the gas with the oil efficiently and slow down the mobility of the gas slugs.

Fig. 9 shows the gas production during the WAG floods. The flood with a WAG ratio of 1 and a slug size of 0.01 PV has the latest breakthrough and lowest gas production of the three floods shown. Small slug size stabilizes the gas fingers and slows down gas breakthrough. The WAG flood with a slug size of 0.05 PV has an earlier breakthrough. In fact, the breakthrough in the gasflood (WAG ratio = 0), is at about 0.08 PV, a little bit higher than 0.05 PV. Thus, it is expected that the first gas slug in the 0.05 PV slug size case travels close to the production well when the first water slug is injected. The water slug, however, breaks up the first gas slug and

slows down its propagation. The gas production in the WAG floods is significantly lower than that in gas floods. Thus the utilization of gas is better in the WAG floods.

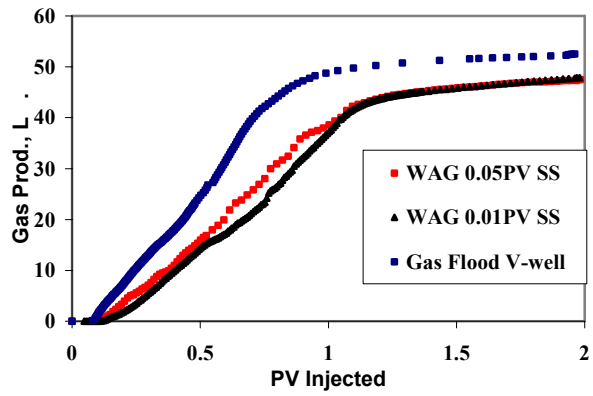

Fig. 9 - Gas production during WAG injection in the quarter 5-spot model

Fig. 10 shows the pressure drop in the WAG flood with 0.05 PV slug size. The pressure drop decreases sharply during the injection of the first solvent slug. Pressure drop jumps when water slugs are introduced, but these jumps decrease with subsequent slugs. During the gas flood, the pressure decreases sharply during the gas flood and increases back up during the waterflood. The final pressure drop is similar in both these floods.

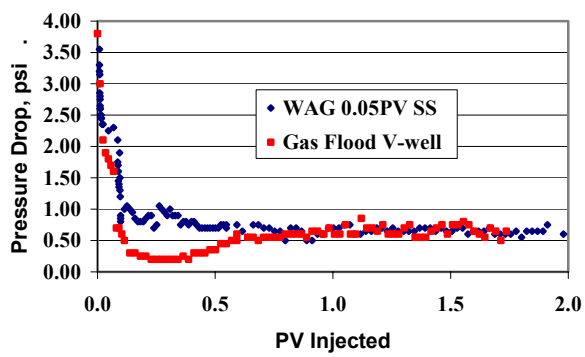

Fig. 10 – Pressure drop in the quarter 5-spot model during WAG floods

Simulation. Three and four phase simulations are done in a quarter of a five spot pattern with vertical injector and producer wells. Both homogeneous and heterogeneous permeability fields

are generated for the purpose of simulation. A homogeneous permeability field of 300 md is used for the laboratory-scale simulations. Two different heterogeneous permeability fields are generated by unconditional Gaussian simulation using GSLIB. The first permeability field is shown in **Fig. 11** and referred to as Perm 1. Permeability values vary from 200 md to 1200 md with a mean of 636 md and standard deviation of 383 md. Another heterogeneous permeability distribution (Perm 2) is constructed as shown in **Fig. 12**. Permeabilities lie in the range of 300-800 md with a mean of 450 md and standard deviation 67 md. Injector and producer well pressures are fixed at a constant bottomhole pressure. Both vertical and horizontal production wells are used in the simulations. Horizontal well is placed in the bottom most layer of a 3 dimensional reservoir.

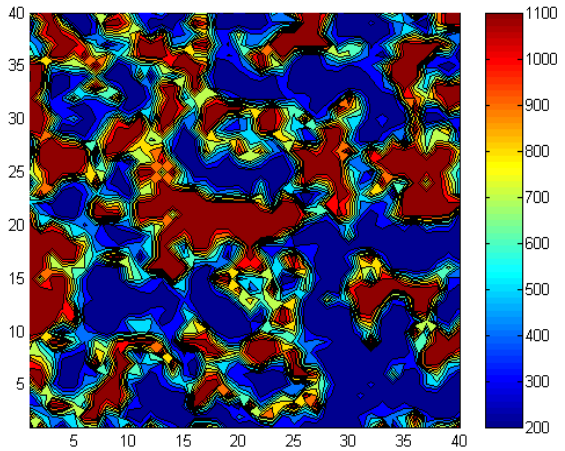

Fig. 11 - Heterogeneous permeability distribution (Perm 1)

Several oil and solvent compositions are used to study three-phase and four-phase behavior. Laboratory-scale simulations are performed with a reservoir oil (called Oil 1) described in Table 3. Twelve pseudo-components are used to represent the oil with a viscosity of 50 cp by a Peng-Robinson equation of state. It mainly consists of methane and C9+ components. Critical volumes of a few components are adjusted to attain the desired oil viscosity.

Compositions of NGL (natural gas liquid) and LG (lean gas) are shown in Table 4. Three different types of solvents, 80 %CO_2 -20% NGL, 50 %CO_2 -50% NGL and LG are used and their effect on the oil recovery in the 5-spot model is investigated. Oil saturation during 1-D simulations of oil displacement by gas (in a slim tube at 1300 psi) is plotted in **Fig. 13** for all the three solvents. It indicates that 80 %CO_2 -20% NGL and 50 %CO_2 -50% NGL are multicontact miscible and LG is immiscible with the reservoir oil.

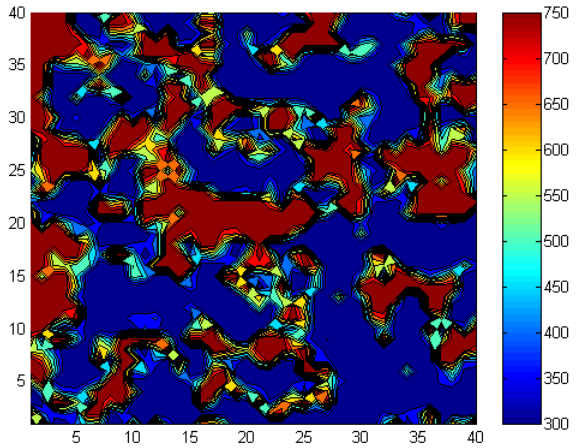

Fig. 12. Heterogeneous permeability distribution (Perm 2)

Name	Composition
CO_2	0.000436
C1	0.272149
C2	0.004128
C3	0.010484
C4	0.021230
C5	0.020020
C6	0.022566
C7-9	0.098746
C10-13	0.100533
C14-19	0.145138
C20-35	0.164159
C36+	0.140411

Table 3 - Oil 1 composition used for four-phase laboratory-scale simulation

Name	NGL	LG
CO_2	0	0.12179
C1	0	0.76587
C2	0	0.06242
C3	0.0439	0.03133
C4	0.4337	0.01108
C5	0.2543	0.00329
C6	0.1198	0.00422
C7-9	0.1483	0

Table 4 - Composition of NGL and LG

Name	Composition
CO_2	0.001
C1	0.199
C6	0.4
C36 +	0.4

Table 5 - Oil 2 description used for four-phase field-scale simulations

Name	Composition
C1	0.001
C3	0.199
C6	0.4
C14-19	0.4

Table 6 - Oil 3 composition for three-phase field-scale simulations

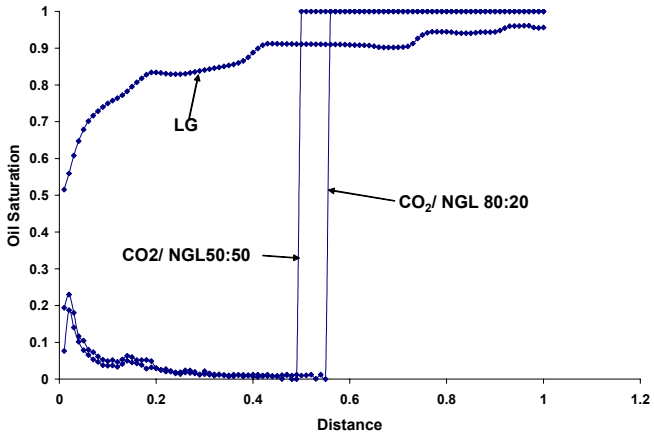

Fig. 13 - Oil saturation in 1D simulations (Oil 1)

For field-scale simulations, to reduce computational time and space, the oil composition is approximated by a four-pseudo-component oil, called the Oil 2. The composition of Oil 2 is shown in Table 5; it consists of mainly methane, hexane and C36 plus fractions. The oil viscosity is 11 cp. This composition mimics the phase behavior of Oil 1, but the CPU time spent in flash calculations is reduced. **Fig. 14** shows the oil saturation profile during 1D simulations of oil displacement by pure CO2 (at 1200 psi) at 0.5 PV injected. Solvent is multicontact miscible with the oil at the simulation conditions.

Parameter	Value
DX (ft)	0.041
DY (ft)	0.041
K (md)	300
Initial Pressure (psi)	1200
Initial Water Sat	0.25
Wag Ratio	1
Slug Size	0.05

Table 7: Simulation conditions for four-phase laboratory simulations

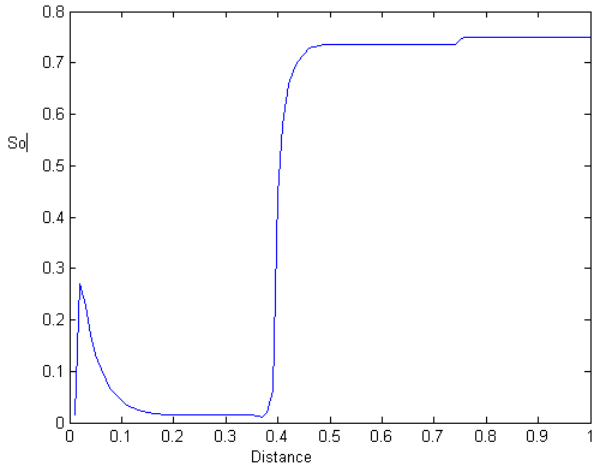

Fig. 14 - Oil saturation in 1D simulation (Oil 2)

Some field scale simulations are run with a system with no third hydrocarbon phase for comparison with common reservoir simulators (e.g., ECLIPSE). The oil composition chosen for

these simulations is Oil 3; it is described by four pseudo components as shown in Table 6. Parameters are adjusted to obtain an oil viscosity of 50 cp. Oil saturation profile during 1D simulation of oil displacement by 60%C1+40%C3 is shown in **Fig. 15a**. This is the minimum enrichment of methane with propane to attain multicontact miscibility. Below 38 % propane - in the solvent, the oil recovery falls sharply as the propane enrichment is reduced, as shown in **Fig. 15b**.

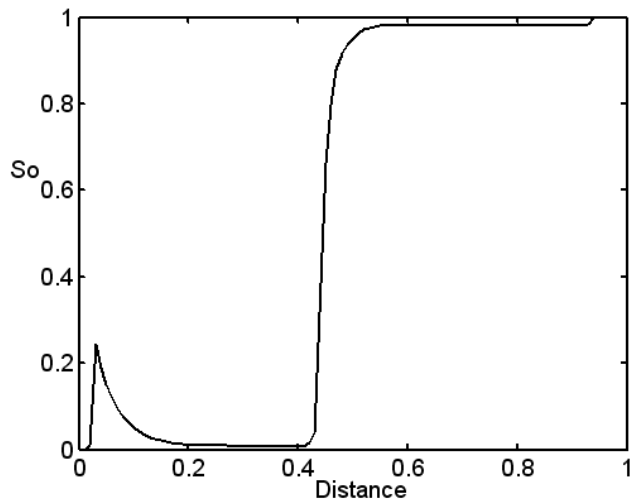

Fig. 15a - Oil (Oil 3) saturation in 1D simulation (Solvent C1/C3 = 60/40)

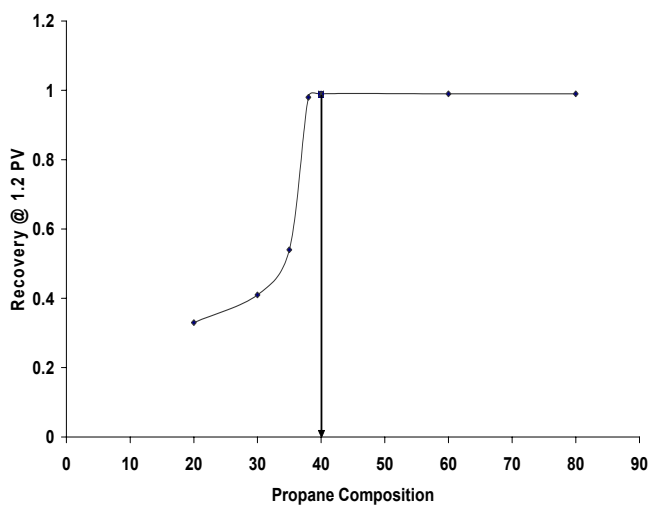

Fig. 15b - Recovery vs. enrichment

Four-Phase System

Laboratory Case: 2-D laboratory-scale quarter 5-spot simulations are performed with 20 grid blocks in X-direction and 20 grids in Y-direction. The permeability field is assumed to be homogeneous with a permeability of 300 md. Initial pressure is set at 1200 psi and temperature is set at 82 ^{0}F. Constant pressure drop of 10 psi is applied across the quarter 5-spot cell. The initial water saturation is 0.25, which is also the irreducible water saturation. 80%CO_2 -20% NGL (natural gas liquid) mixture is used as a solvent and injected into the 50 cp Oil 1 alternately with water in a WAG process. WAG ratio is chosen to be 1 with a constant slug size of 0.05 PV. A total of 0.4 PV of solvent is injected after which only water is injected. Table 7 lists the simulation conditions.

Fig. 16 shows the pressure profile at 0.32 PV injected. Pressure contours are almost symmetric due to homogeneous nature of the medium. **Fig. 17** provides the water, gas, oil, and second liquid phase saturation profiles at 0.32 PV. Oil phase is continuously displaced by water and gas; oil saturation profile decreases monotonically along the diagonal joining the injector and the producer. The second liquid phase is present in a lot of grid blocks. Gas phase exists in only a few grid blocks, only near the displacement front. Sweep is very efficient due to homogeneous permeability field and water injection after every slug of solvent. WAG helps in decreasing the mobility contrast between oil and solvent and results in stable displacement fronts.

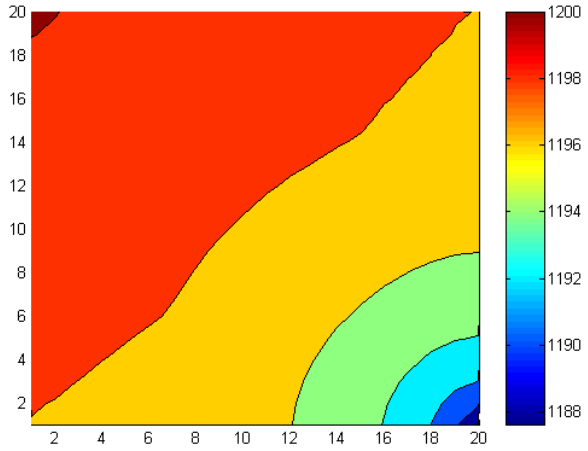

Fig. 16 - Pressure profile @ 0.32 PV for laboratory-scale simulation

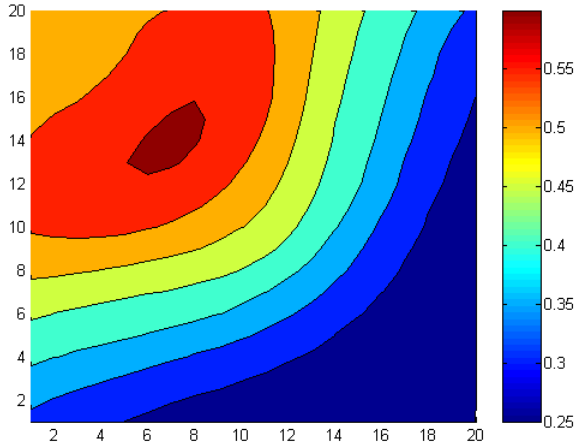

Fig. 17a - Water saturation profile @ 0.32 PV for laboratory-scale simulation

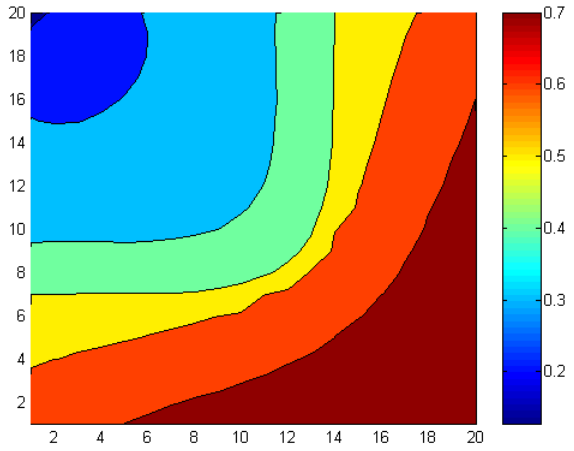

Fig. 17b - Oil saturation profile @ 0.32 PV for laboratory-scale simulation

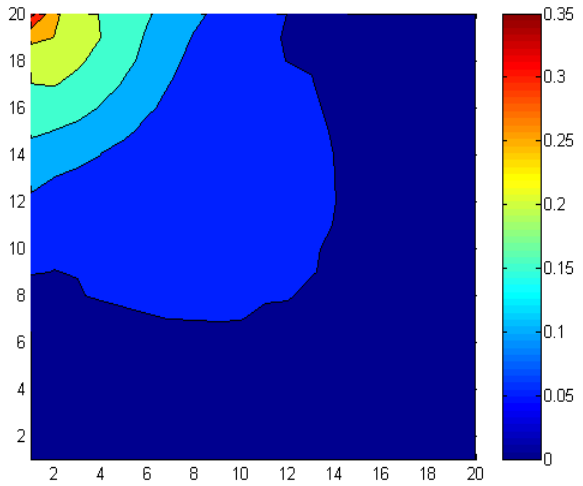

Fig. 17c - Second liquid phase saturation profile @ 0.32 PV for laboratory-scale simulation

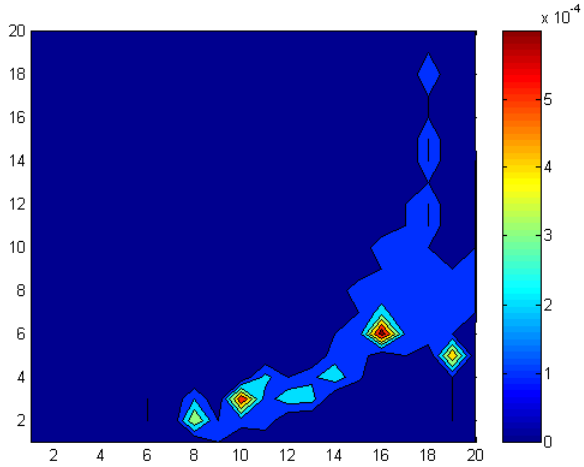

Fig. 17d - Gas saturation profile @ 0.32 PV for laboratory-scale simulation

The solvent composition was varied to investigate the effect of solvent on oil recovery in these WAG floods. Two other solvents, 50 %CO_2 -50% NGL and pure LG are studied in the WAG injection processes with WAG ratio of 1 and slug size of 0.05 PV. Table 4 lists the composition of LG used in the simulation. **Fig. 18** shows the oil recovery for the three different solvents. It is observed that NGL helps in improving the oil recovery. It can be seen that recovery goes up as we increase the concentration of heavier components in the solvent by adding some NGL in the injectant.

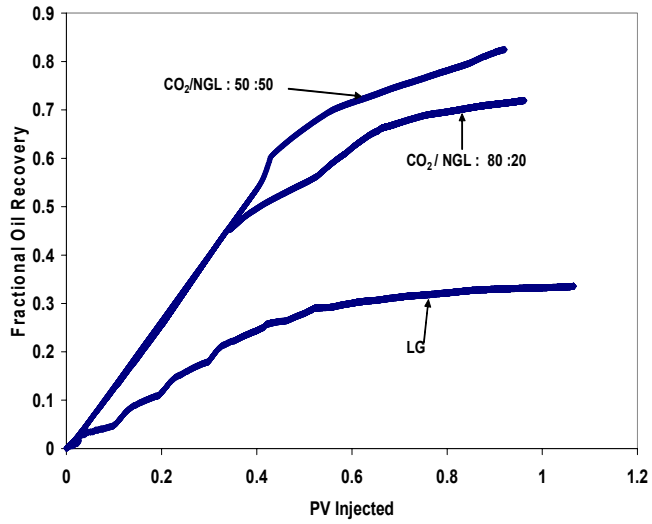

Fig. 18 - WAG Recovery for three different solvents

Parameter	Value
DX (ft)	12
DY (ft)	12
Initial Pressure (psi)	1500
$P_{bottomhole}$ Injector (psi)	1800
$P_{bottomhole}$ Producer (psi)	1100
Initial Water Sat	0.25
Wag Ratios	0,0.5,1
Slug Size	0.05

Table 8: Simulation conditions for four-phase field-scale simulations

Field Case: 2-D field-scale quarter 5-spot simulations are performed with 40x40 grid blocks. Heterogeneous permeability fields, Perm 1 and Perm 2 are used for these field-scale simulations. Both the injector and producer wells are vertical and set at a constant bottomhole pressure of 1800 psi and 1100 psi, respectively. Pressure drop between the two wells is kept constant. Initial reservoir pressure is 1500 psi with an initial water saturation of 0.25. Pure CO_2 is injected into the reservoir with Oil 2 (with a viscosity of 11 cp) and four-phase behavior is observed at 82 ^{0}F. WAG injection is conducted in three permeability fields (Perm1, Perm2 and homogeneous). It is also studied at the WAG ratios of 1 and 0.5 (slug size of 0.05 PV) and compared with the

continuous gas injection process. Table 8 lists the details of the simulation model used in the field case study.

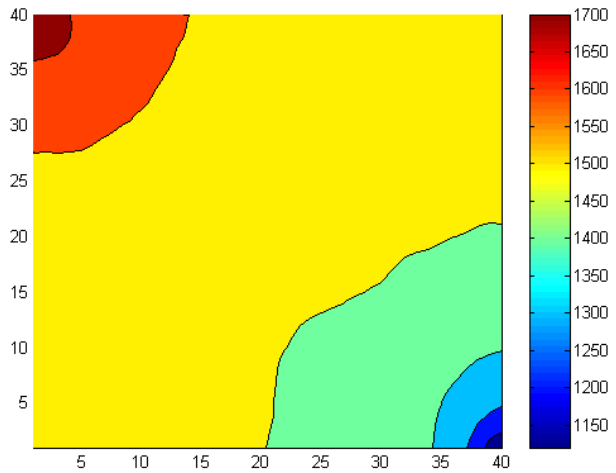

Fig. 19 - Pressure profile @ 0.17 PV for field case (Perm 1, WAG Ratio 1)

Fig. 19 shows the pressure profile at 0.17 PV injected for the WAG ratio of 1 and slug size of 0.05. Pressure contours are not circular because of the heterogeneous permeability field of Perm 1. It can be observed that the pressure drop near the production well is very high because of the converging flow of the viscous oil towards the production well. Saturation distribution of the second liquid phase and the oil phase are shown in **Figs. 20** and **21**, respectively. Fluids follow the path of high permeability regions resulting in unsymmetric and wavy fronts. Second liquid phase, a CO_2-rich phase is formed in a lot of gridblocks.

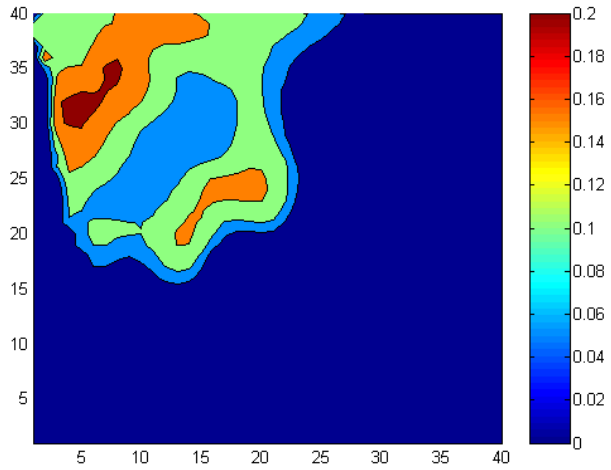

Fig. 20 - Second liquid phase saturation profile @ 0.17 PV for field case (Perm 1,WAG Ratio 1)

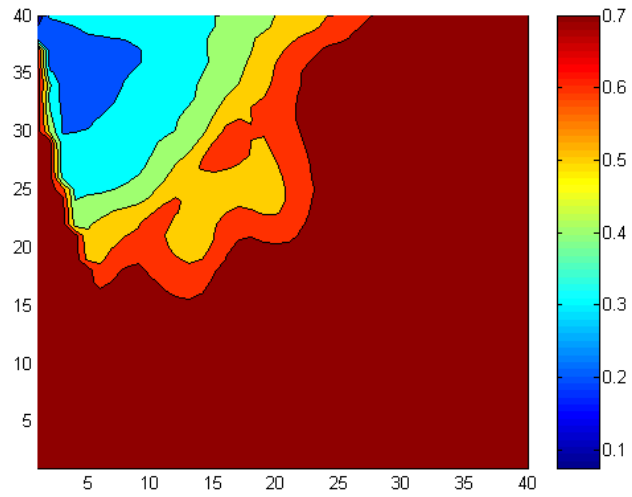

Fig. 21 - Oil saturation profile @ 0.17 PV for field case (Perm 1,WAG Ratio 1)

Permeability heterogeneity is an important factor in determining sweep efficiency. The effect of permeability heterogeneity is studied by comparing the WAG floods in Perm2, Perm 1 and homogeneous fields. WAG simulations are run under identical conditions (as in Fig. 21 for Perm 1) and oil saturation profiles for Perm 2 and the homogeneous field are plotted in **Fig. 22** and **23**, respectively. Perm2 is less heterogeneous than Perm 1; the oil saturation contours are more smooth in **Fig. 22** than in **Fig. 21**. Saturation contours in the homogeneous case (Fig. 23)

are almost circular. Oil saturation profiles clearly show that heterogeneity is an important factor that affects the sweep efficiency of any process.

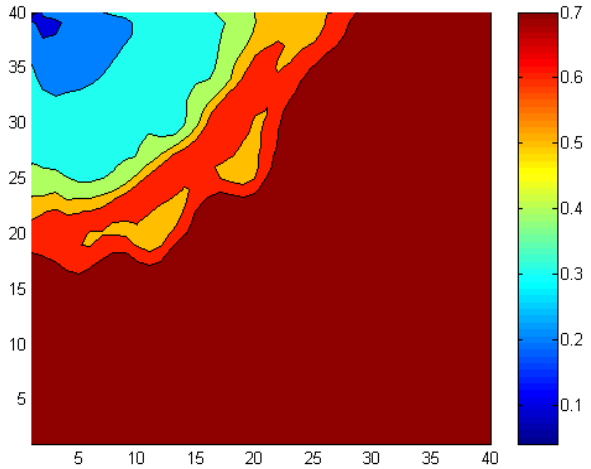

Fig. 22 - Oil saturation profile@0.17 PV for field case (Perm 2, WAG Ratio 1)

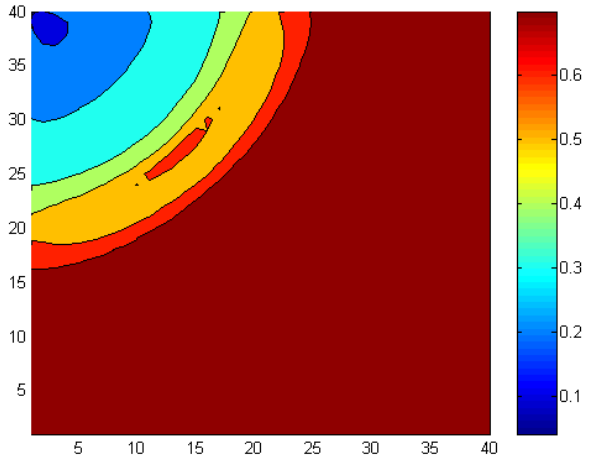

Fig. 23 - Oil saturation profile@0.17 PV for field case (Homogeneous, WAG Ratio 1)

WAG ratio is another important factor in determining sweep efficiency. **Fig. 24** shows the oil saturation distribution during a continuous gas (CO2) injection (WAG ratio = 0) at 0.17 PV injected in the heterogeneous permeability field of Perm 1. The high viscosity ratio between gas and oil leads to formation of viscous fingers along high permeability channels and adversely affects the areal sweep. The oil saturation distribution for the WAG ratio = 0 in Fig. 24 can be

compared with that of WAG ratio = 1 in Fig. 21. The fingers are dampened and the sweep efficiency is improved to some extent by alternate water and gas injection. **Fig. 25** shows the oil saturation profile for the WAG ratio 0.5. Comparing Figure 11 (WAG ratio 1), Fig. 24 (WAG ratio 0) and Fig. 25, it can be inferred that as the WAG ratio increases the sweep efficiency increases.

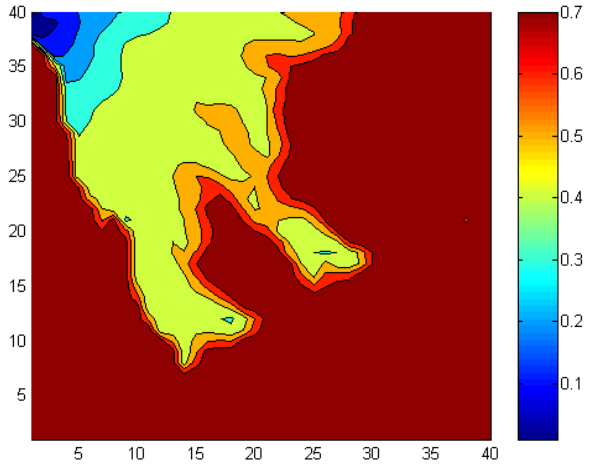

Fig. 24 - Oil saturation profile@ 0.17 PV for field case (Perm 1, WAG Ratio 0)

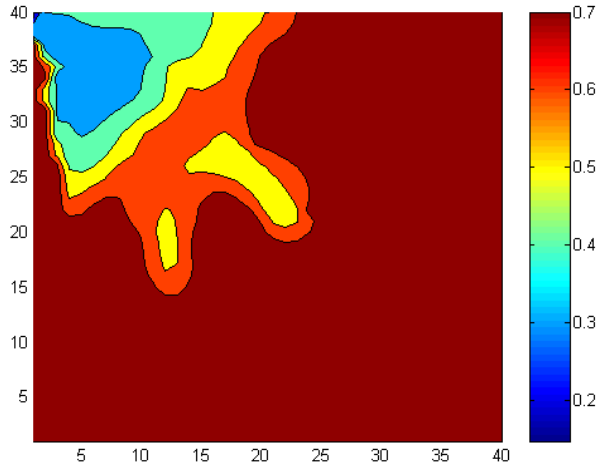

Fig. 25 - Oil saturation profile@ 0.17 PV for field case (Perm 1, WAG Ratio 0.5)

Parameter	Value
DX (ft)	12
DY (ft)	3
Initial Pressure (psi)	1700
$P_{bottomhole}$ Injector (psi)	1800
$P_{bottomhole}$ Producer (psi)	1100
Initial Water Sat	0.20
Wag Ratio	1
Slug Size	0.05

Table 9: Simulation conditions for three-phase field-scale simulations

Three-Phase System

Field Case: Oil 3 is used here to avoid the appearance of the second liquid phase. These WAG displacemnts can also be simulated using traditional reservoir simulators. 60/40 mixture of methane and ethane is used as a solvent during the WAG injection. The reservoir oil (Oil 3) has a viscosity of 50 cp. Simulations are conducted on a vertical crossection with vertical injection and producer wells. 1600 gridblocks are used in a Cartesian X-Z plane with 40 grids in the X-direction and 40 grids in the Z-direction. Homogeneous permeability field is used with a permeability of 250 md. Solvent and water are injected alternately with a constant slug size of 0.05 PV and a WAG ratio of 1. Initial reservoir pressure is 1700 psi with an initial water saturation of 0.20. Temperature of the reservoir is set at 140 ^{0}F. Table 9 lists the parameters for these simulations.

Fig. 26 shows gas, water and oil saturation profiles. Effect of gravity is very well seen in the contours. Gas, being lighter than oil and water, moves up and water settles down as the displacement fronts propagate. Oil gets miscibly displaced on the top portion of the reservoir. The lower portion of the reservoir is not swept by gas properly. It is waterflooded and hence oil recovery is low in the lower portion of the reservoir. Thus, the oil saturation contours and gas saturation contours look similar and very different from the water saturation contours.

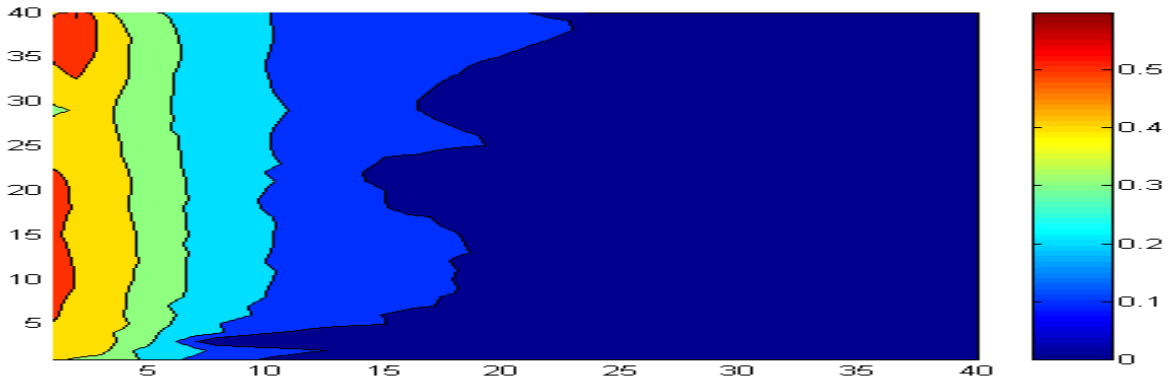

Fig. 26a - Gas saturation profile for WAG Ratio 1 (Kv /Kh = 0.1) (X-Z Cross-section)

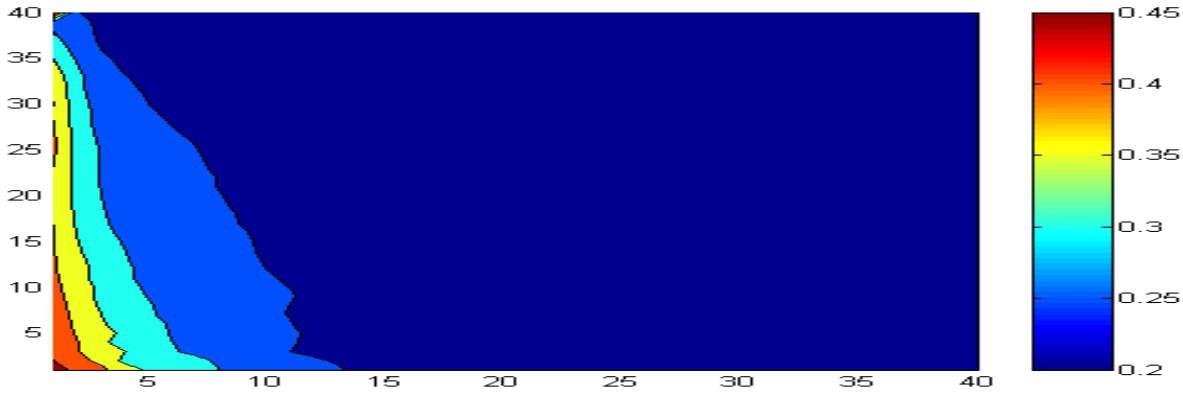

Fig. 26b - Water saturation profile for WAG Ratio 1 (Kv /Kh = 0.1) (X-Z Cross-section)

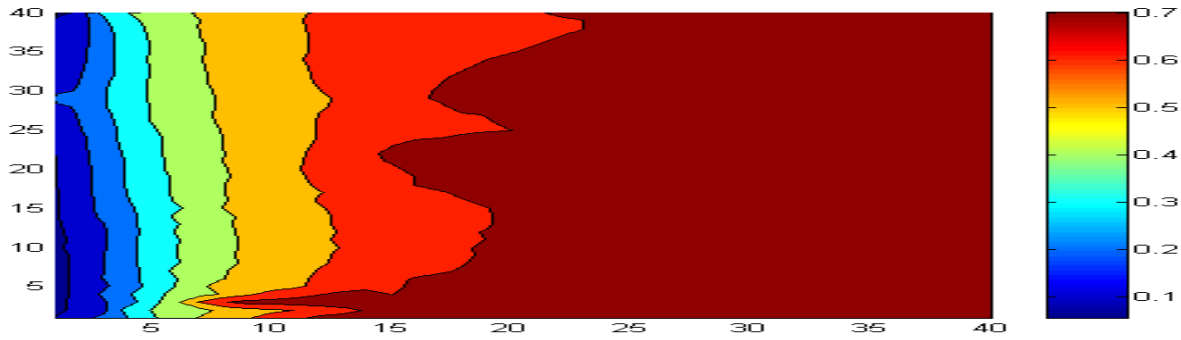

Fig. 26c - Oil saturation profile for WAG Ratio 1 (Kv /Kh = 0.1) (X-Z Crossection)

3-D WAG simulations are conducted with the same composition oil (Oil 3) and solvent, but the oil viscosity is 13 cp. 8000 gridblocks are used to represent a 3-dimensional reservoir block with 40 grids in X-direction, 40 grids in Y-direction and 5 grids in Z-direction. Reservoir

size is 480 ft * 480 ft * 50 ft. Homogeneous permeability field is used with $K_x = K_y = 300$ md and $K_z = 30$ md. Horizontal production well is located at the bottommost layer with a length of 360 ft covering 3/4th of the side of the reservoir block. WAG ratio is 1 and slug size 0.05 PV.

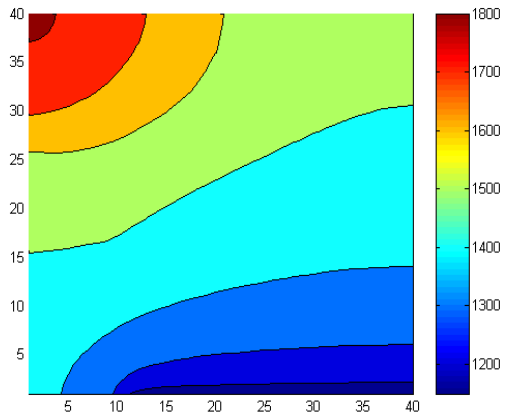

Fig. 27 - Pressure profile @ 0.20 PV injected

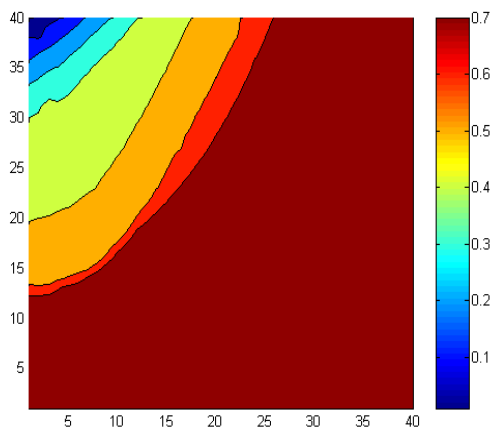

Fig. 28a - Oil saturation @ 0.20 PV injected

Pressure distribution in the bottom most layer at 0.2 PV injection is shown in **Fig. 27**. Pressure contours for the constant saturations for the horizontal production well look different from those of vertical production well. They are unsymmetric due to the presence of the horizontal well. It is also observed that the pressure drop near the production well is low because the fluid enters the well through a larger surface. **Fig. 28** shows oil and gas saturation profiles of

the bottom most layer at 0.2 PV injected. Streamlines bend towards the horizontal well and hence saturation contours are also non-circular. The horizontal production well affects the sweep of the reservoir causing earlier breakthrough compared to vertical production wells.

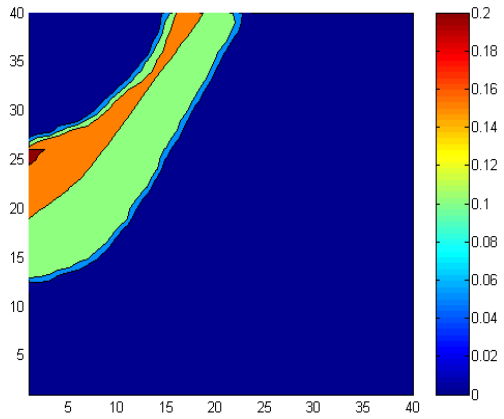

Fig. 28b - Gas saturation @ 0.20 PV injected

Conclusions

A high-pressure quarter 5-spot cell has been constructed to conduct multicontact miscible WAG displacements at reservoir conditions. Multicontact miscible solvents are identified by conducting slimtube experiments for a medium viscosity oil (78 cp). Coreflood experiments are conducted to determine microscopic displacement efficiency as a function of WAG ratio. Quarter 5-spot experiments are conducted to infer sweep efficiency in a 3D geometry at the laboratory scale. A compositional model has been developed to simulate such displacements in laboratory and field. The following observations are made:

- Ethane is a multicontact miscible solvent for oil B at pressures higher than 1340 psi. WAG improves the microscopic displacement efficiency (~100%) over continuous gas injection followed by waterflood (~67%) in corefloods. (Task 1)
- WAG improves the oil recovery (~75%) in the quarter 5-spot over the continuous gas injection followed by waterflood (~64%). WAG injection slows down gas breakthrough. A decrease in the slug size improves the oil recovery in WAG floods. Use of a horizontal production well lowers the oil recovery over the vertical production well during continuous gas injection. (Task 2)
- The sweep efficiency has not been measured directly in the quarter 5-spot cell, but it is expected that as the recovery increases so does the sweep efficiency. These experiments will be matched by compositional simulations to infer the sweep efficiency of these processes. (Task 3)

Plans for Next Reporting Period

- Gas floods and WAG floods in the quarter five-spot model (Task 2)
- 3D modeling of the quarter five-spot model (Task 3)

Milestones Not Met

- None

Cost Status

	Approved budget for Year 1		Actual spending so far	
	DOE ($)	Cost share ($)	DOE ($)	Cost Share ($)
Personnel	91,254	22,854	46,304	4,935
Fringe	21,016	5,020	6,804	1,084
Travel	2,400			
Equipment	20,000	30,000	24,846	30,000
Supplies	12,000		1,654	
Total Direct	146,670	57,874	73,608	36,019
Indirect charges	61,435	13,519	23,650	2,919
Total	208,105	71,393	97,258	38,938

Schedule Status

Identification Number	Description	Planned Completion Date	Actual Completion Date	Comments
DE-FC26-04NT 15535	Slimtube Tests	3-05	3-05	On schedule
	High P Model Construction	3-05	3-05	On schedule
	1D Compositional Model	3-05	3-05	On schedule
	Corefloods	9-05	9-05	On schedule
	Gasfloods	3-06		Started
	3D Modeling of Gas/WAG Fld	9-06		Started
	WAG Floods	9-07		Started
	Foam Floods	9-07		
	3D Modeling of Foam Floods	9-07		
	Field Simulations	9-07		

Significant Accomplishments

Project got started in December, 2004. Equipments have been assembled. Slim tube experiments have been conducted. 5-spot gasflood and WAG floods and their numerical modeling are under way.

Anticipated Problems

None

Technology Transfer

We presented two papers (SPE 96940, SPE 97198) for 2005 SPE Fall conference on the basis of our work. We have received reservoir oils from BP and ConocoPhillips for this study and presented our results to their company representatives.