Experimental and Simulation - Assisted Feasibility Study of Gas Injection to Increase Oil Recovery Using a Combination of Semi-VAPEX and GAGD Techniques

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ABSTRACT: *Gas injection into heavy oil reservoirs could result in high ultimate recovery of oil. Experimental studies showed that an application of a combined technology of Gas Assisted Gravity Drainage (GAGD) and Vapor Extraction (VAPEX) could increase final oil recovery of a candidate viscous oil reservoir. In this paper the results of laboratory investigation are presented, including Pressure-Volume-Temperature (PVT) studies, physical model experiments and simulation studies to evaluate the gas injection process for heavy oil reservoirs recovery. The study examined the effect of two different gases on viscosity reduction and oil swelling. Physical model tests were carried out to investigate the effect of gas injection on oil recovery. Another study (simulation model) predicted the performance of the reservoir under gas injection in a model. This simulation study was established on a sector of the reservoir.*

KEY WORDS: *Gas injection, Heavy oil, Gravity drainage, Vapor extraction, Oil recovery.*

INTRODUCTION

Increase in the world energy demand and decrease in conventional oil reserves coupled with increasing rate of oil price bring not only the viscous oil deposits to an increasing attention but also makes the application of EOR processes are unavoidable practice to increase recovery from conventional hydrocarbon deposits. Here, the term “viscous oil” means oils, which can be produced naturally with low final recovery (less than ten percent) if the course of natural depletion is to be examined. Gas flooding of these oils especially in the case of thick net pay and hiring vertical wells do not seem to be a promising scenario due to highly unfavorable mobility ratio and gas override. If this scenario is being implemented using vertical wells in reservoirs having no dip, as simulation runs showed, early breakthrough of injection gas will result. This will adversely affect the overall efficiency of project and consequently its economy.

Recovery from heavy oil reservoirs has a long history in oil industry and is a very mature technology. In these types of oil deposits, different production mechanisms are available which can be accommodated into two main categories of thermal and non-thermal production methods.

Unlimited number of papers can be easily found in the open literatures, which discuss different issues and advancements in the heavy oil recovery. The contents of these papers cover both experimental and practical

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aspects which rang from basic information, advantages and disadvantages of each method, different aspects of PVT properties of heavy oils and their changes in thermal methods and also due to mixing with light gases and solvents and also numerical modeling of available production techniques.

Among non-thermal methods vapor extraction or VAPEX process is one of the youngest methods [1]. This method does not have the big disadvantage of thermal methods, which is heat loss especially in thin net pays. In this process, a solvent is kept in contact with heavy oil and due to its dissolution the oil viscosity decreases. The resulted low-viscous oil is then drained and produced. *Butler* and *Jiang* [2] experimentally investigated the use of widely spaced horizontal injector and producer wells in VAPEX process. Experimental results showed the success of this application.

The drilling of horizontal wells has expanded rapidly during the last few years. These advances resulted in drilling cost-effective horizontal legs sometimes more than thousand of feet. The advantage of horizontal wells versus vertical wells is that horizontal wells can be drilled parallel to bedding and along a formation strike, thus opening up more of the formation to the wellbore.

Joshi [3] provided an extensive list of references on horizontal well technology and presented equations of steady-state flow. *Butler* and *Stephens* [4] and *Joshi* and *Threlkeld* [5] described the application of horizontal wells in thermally stimulated heavy oil reservoirs. Both works present the results of calculations and experiments on gravity-drainage oil recovery into horizontal wells stimulated by steam injection.

High recovery values have been indicated for gravity drainage. *Dumore* and *Schlos* [6] during their capillary pressure studies discovered that residual oil saturation after gas injection could be extremely low (5 %) in highly permeable sandstone cores containing connate water. They also found low residual oil saturations in sandpack gravity drainage experiments. A field study by *King* and *Stiles* [7] concerns the east Texas Hawkins reservoir, in which very high displacement efficiency for gravity drainage was reported (87 %).

Gas injection is one of the oldest EOR methods. Today, this recovery method is applied to increase oil recovery from both light and heavy oil deposits. This technique is of great interest especially in heavy oils where due to high reservoir depth, thin pay thickness, low porosity and so on thermal method cannot be easily employed as dictated by high rate of heat loss. Gravity stabilization is of great importance for successful implementation of this technique. In the absence of natural dip, this gravity stabilization may be achieved by injection through horizontal wells placed on top of the reservoir while producers are horizontal wells placed at the bottom. It was found by *Bansal* and *Islam* [8] that high recovery number (around 65 %) can be achieved in a successful implementation of this type of gas injection. Even though similar ultimate recovery can be obtained by gravity drainage alone, but the time to reach such a recovery is extremely long. Recently, GAGD was found by *Rao et al.,* [9] to be a promising technology to be applied to oil reservoirs to maximize recovery in thick reservoirs even with smooth dip.

In this paper the results of experiments are presented which were conducted to investigate the use of a combination of GAGD and semi-VAPEX processes to increase the final oil recovery in one of Iranian viscous oil reservoirs. The mentioned reservoir rock is un-consolidated sandstone with an average porosity of 38 % and permeability of 1.5 to 3 darcies. The initial reservoir pressure was 3500 psi and it has declined to 1000 psi due to production. The average reservoir temperature is 180 ^{o}F.

In this reservoir, oil with three different API gravities were deposited in three producing zones. Low recovery value was observed during considerable decrease in the initial reservoir pressure, which was much above its saturation pressure. This low recovery was attributed to the high viscosity of reservoir oils. Thermal methods did not seem to be promising due to high reservoir depths. Water and gas flooding scenarios, using current vertical wells, were investigated in simulation studies and did not show good final recovery. Deficiency of these injections, that manifest themselves in early breakthrough of the injection fluids, was thought to be due to unfavorable mobility ratios due to high oil viscosity especially in the case of gas injection.

Since previous studies [10], sited in the literature, have shown that downdip gas injection is very effective to increase oil recovery through hastening gravity drainage; for this reservoir, it was proposed to inject gas at the current reservoir pressure, which is still much

Table 1: Properties of test oils used in the swelling experiments.

Sample No.	°API	GOR (SCF/STB)	Pb (psi)	Bo (RESB/STB)
Oil A	20.5	90	516	1.09
Oil B	17.5	63	462	1.07
Oil C	14.6	62	443	1.07

Table 2: Properties of two candidate injection gases.

Components	Gas A (mol %)	Gas B (mol %)
N_2	0.504	0.561
CO_2	0.570	4.070
H_2S	0.000	5.757
C_1	82.413	76.043
$C_2 – C_5$	15.941	13.307
C_{6+}	0.572	0.262

above its saturation pressure. This injection will be initially through long horizontal wells, which will be drilled, at the bottom of its thick net pay at the same time let the gas to bubble into the oil in the course of its trip to the top of the reservoir. The dissolved gas was expected to change the phase behavioral and dynamic properties of oil like Bo, Rs and μo. The most important objective was to decrease oil viscosity, hence, increase oil production rate and ultimate recovery. Gas injection is halted when the producing gas to oil ratio in the most top vertical wells increases considerably. Then the production is started from bottom horizontal wells and gas is injected through horizontal legs at the top of the reservoir. Several experiments were proposed to investigate different laboratory aspects of the proposed method. These included swelling tests, gas flooding in a vertical physical model and possibility of asphaltene precipitation and probable pore plugging.

EXPERIMENTAL WORK

Swelling Tests

The experiments were performed in a high pressure, high temperature PVT apparatus consisting of high pressure and high temperature cell, high pressure pump, gasometer and high pressure and high temperature viscometer constructed from standard components. The first sets of experiments were some swelling tests at different contact pressures of reservoir oils and candidate injection gases. When a gas and a live oil sample come to contact at a pressure above the initial bubble point of the oil then gas will dissolve in oil. This will result in oil swelling, will increase oil formation volume factor, and will decrease oil viscosity. In the target reservoir, as it was mentioned before, the current reservoir pressure is much above the saturation pressure.

In each swelling test experiment a representative sample of the reservoir oil was obtained by recombining samples of oil and its corresponding separator gas at its solution ratio. This recombined sample was put in a PVT cell at reservoir temperature (180 ^{o}F) and saturation pressure. Swelling tests were carried out using two hydrocarbon candidate gases from nearby producing reservoirs.

When the equilibrium was reached for the oil sample in the PVT cell one of the gases was injected into the cell at the same temperature. For each volume of injected gas, the new saturation pressure of the oil as well as its volume was measured. Solution gas to oil ratio could be easily measured knowing the initial volume of oil and the standard volume of injected gas. This procedure was followed until the pseudo saturation pressure reached the maximum objective pressure. At each saturation pressure and corresponding solution gas to oil ratio other properties were measured. As it was mentioned before, this reservoir is producing from three producing zones. The fluid properties of these oils are shown in table 1.

Figs. 1 through 9 show the results for the swelling tests conducted on three oil samples by injecting two candidate injection gases (table 2) into these oil samples.

Gas Flooding

Another test was conducted on a vertical physical porous model as in Fig. 10, which was filled with sand pack. The objective of this gas injection test was to evaluate the performance of GAGD in a gravity stable displacement process. The properties of physical model are as follow: porosity 34 %; permeability 2 darcy; diameter 3.57 cm; and height of 40 cm. Initial saturation conditions before gas flooding are 5.11 % water and 94.89 % oil. The temperature is 180 ^{o}F with the injection pressure of 3500 psi.

This model was composed of a three-window cell, which was filled with sand pack. The packed cell was initially saturated with saline water with the equivalent

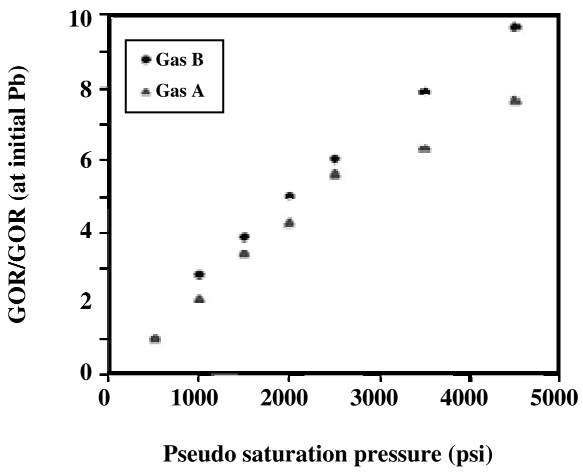

Fig. 1: GOR changes due to gas dissolution in Oil A.

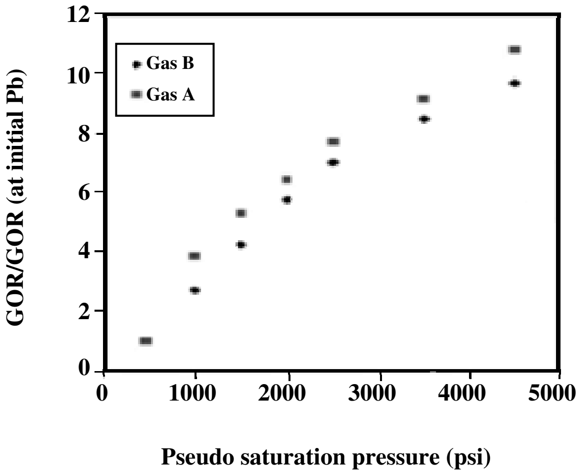

Fig. 2: GOR changes due to gas dissolution in Oil B.

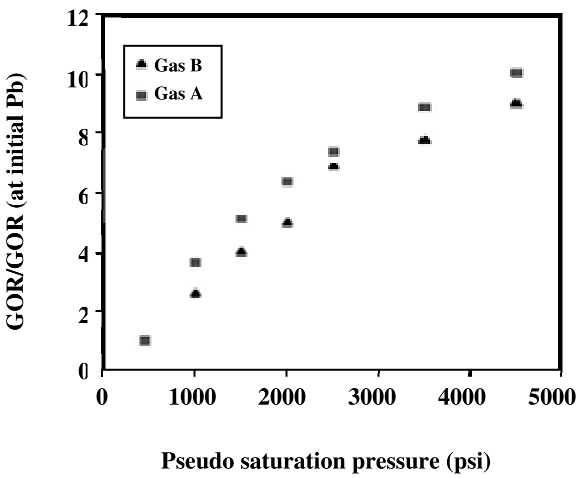

Fig. 3: GOR changes due to gas dissolution in Oil C.

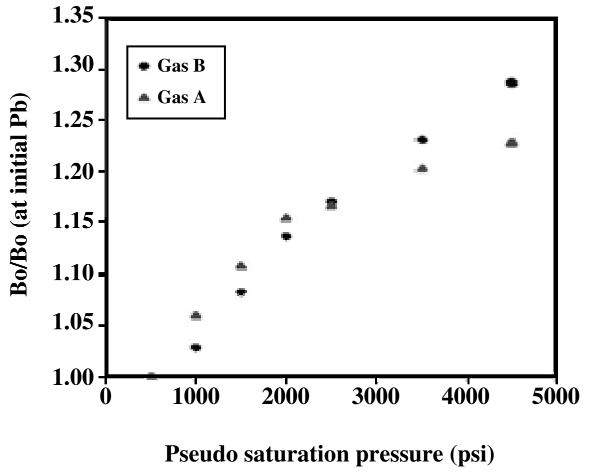

Fig. 4: Changes in FVF due to gas dissolution in Oil A.

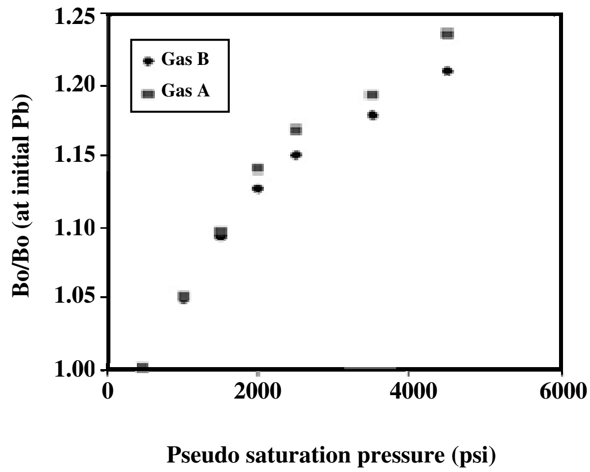

Fig. 5: Changes in FVF due to gas dissolution in Oil B.

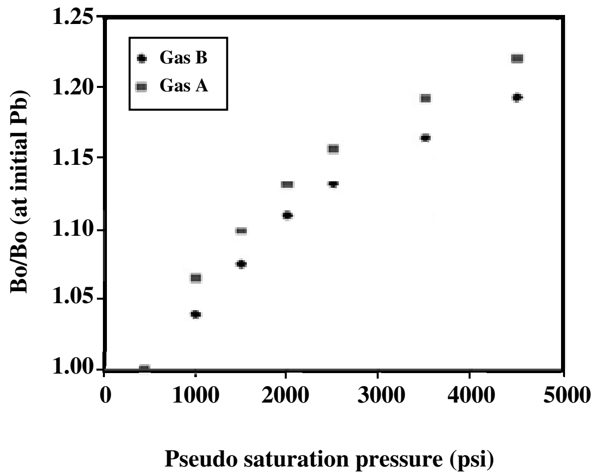

Fig. 6: Changes in FVF due to gas dissolution in Oil C.

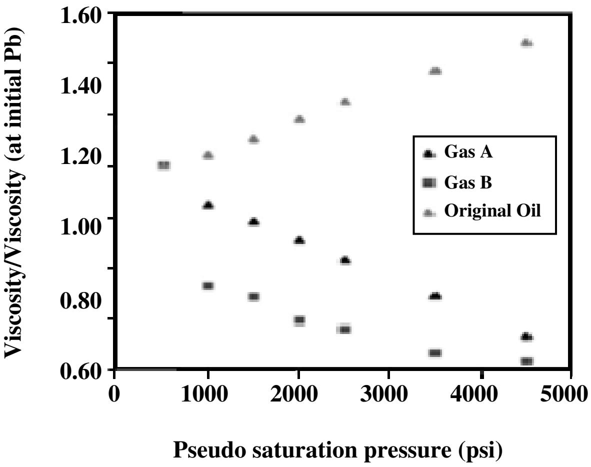

Fig. 7: Viscosity changes due to gas dissolution in Oil A.

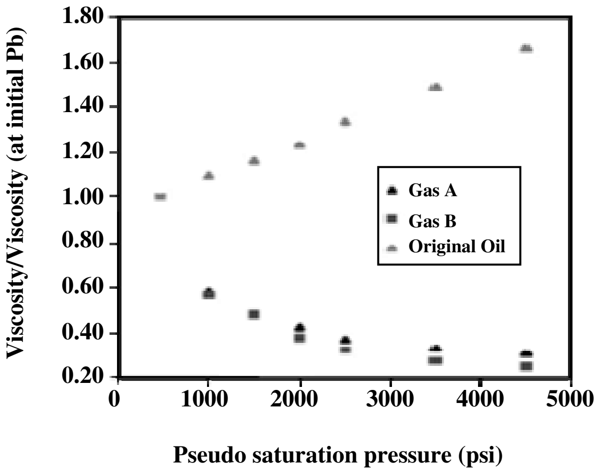

Fig. 8: Viscosity changes due to gas dissolution in Oil B.

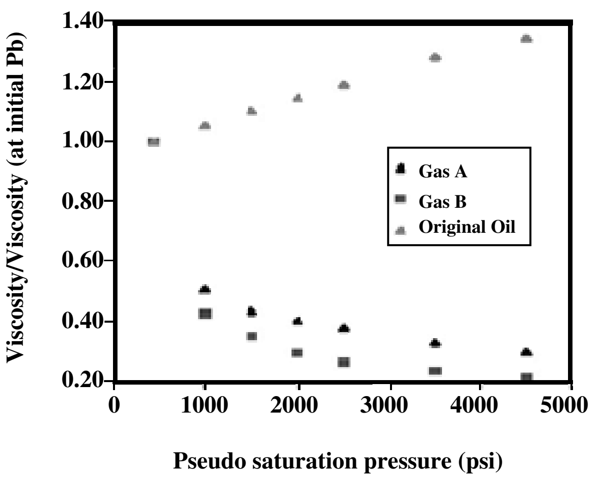

Fig. 9: Viscosity changes due to gas dissolution in Oil C.

salinity to the reservoir brine. This was then flooded with the reservoir oil. Oil injection ceased when no more water came out of the model. At this time the model was ready for gas injection. Initial fluid saturations before gas injection were calculated from material balance on produced and injected volumes of oil and water.

Gas was injected from top into the saturated model at reservoir pressure and temperature while oil was produced from bottom. The rate of gas injection was 2.5 cc/hr. The injection was conducted under constant pressure condition. This was achieved by injecting the gas at constant pressure and controlling the produced fluids outlet pressure with the aid of a backpressure regulator (BPR).

The produced fluids were conducted into a gas oil separator and their volumes were recorded continuously. The gas injection continued until nearly 6 pore volume of gas was injected into the model. The oil production rate decreased after gas breakthrough and no more oil was produced from cell after the injected gas volume exceeded 2.4 PV. The ultimate recovery was found to be around 83 % of IOIP. Results are summarized in Figs. 11 and 12.

Asphaltene Precipitation

The asphaltene deposition problem especially in gas injection projects has often been overlooked and has not receive the attention it really deserves. This is mostly due to two reasons: first of all, low asphaltene contents of light oils and secondly, lack of previous heavy organic deposition experience during production operation in these oils.

Asphaltene deposition during gas injection especially when there is a big potential for dissolution of injected gas into the oil can be a devastating issue, which can result in pore plugging and possible loss of productivity or injectivity even in light oils with very low asphaltene contents (0.2 percent). Although a highly permeable sand reservoir with permeability in the order of few darcies (the reservoir under study) is not likely to be easily plugged, but this test was conducted to assure there would be no problem as it is concerned to high asphaltene content of test oils (more than 10 %).

At each pressure the test was conducted by contacting reservoir oil and injection gas at the desired pressure and reservoir temperature. The volume of injected gas in contact was as much as oil could dissolve at each specific pressure so a single phase system was achieved.

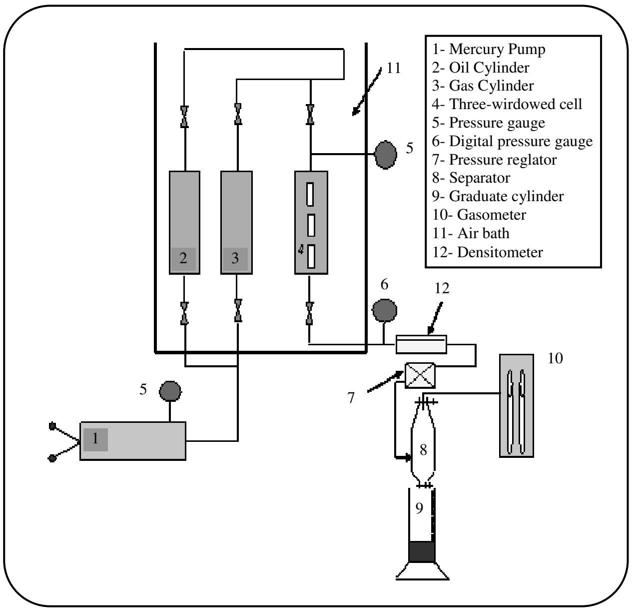

Fig. 10: Schematic representation of set up used in gas injection.

Sufficient contact time was allowed to ensure that equilibrium was reached. The precipitated asphaltene particles were filtered out by passing the oil through a micro size filter. The IP143 standard test procedure was employed to measure the asphaltene content of each sample. The amounts of asphaltene in solution and the precipitated amounts were calculated by comparing the measured initial asphaltene contents and asphaltene contents of the oil after passing through the filter. The difference in these two values showed the precipitated quantity. Typically, the results for dissolution of gas A in different oils are shown in Figs. 13 and 14.

Results showed that, for all oils, as amount of dissolved gas increased more asphaltene would precipitate out of solution. But, it can be easily seen that still very large fraction of asphaltene molecules is in solution even at the highest contact pressure. Taking into account the mass of solution gas in the oil, weight percent of asphaltene contents and precipitated values in the live oil can be easily calculated.

SIMULATION STUDY

Simulation study was conducted to predict the performance of the reservoir under different gas injection scenarios with parallel horizontal wells. These horizontal wells were placed at the bottom of the formation for both gas injection and oil production. The process begins with injecting the gas in each well, in order to contact and soak the oil with gas, around and above the well. Viscosity is reduced as the result of soaking. The well was shut-in for a short period of time after gas injection to allow unsolvable gas migration to the top of the reservoir. Then the well was put on to production. Low oil viscosity was produced at very high rate and very low pressure drawdowns. Several cases were run to determine the optimum spacing between the horizontal wells. Recovery factor of the oil was calculated as 55 % for the best scenario. This phase of study also proved that using long horizontal wells would be beneficial and applicable for higher ultimate recovery with higher oil production rates during the gas injection into oil zone from the bottom of the reservoir.

RESULTS AND DISCUSSION

The results of swelling tests for different combinations of oil and gases are depicted in Figs. 1 through 9. Figs. 1 through 3 show the increase in solution gas to oil ratio. The maximum values show a ten-fold increase in GOR due to gas dissolution. The effect of dissolved gas on the formation volume factor of the oil was also profound and at its maximum was found to be around thirty percent increase as it is shown in Figs. 4 through 6. The oil viscosity on the other side show a reduction to from one third to one quarter of the initial values as it is depicted in Figs. 7 through 9.

It can be easily found that gas B has changed the properties more than that caused by dissolution of gas A. This was resulted from more dissolution of this gas in the test oil samples. This higher dissolution on the other hand resulted from higher sour components (H_2S and CO_2) contents (nearly 10 percent) compared to that of gas A (less that one percent). Although the sour gas was found to be more effective, but the cost of sweetening plant design, construction, installation and maintenance imposed to the project should be thoroughly examined in choosing between the two candidate gases.

The results of gas flooding in the vertical model under gravity stable conditions are shown in Figs. 11 and 12. Fig. 11 shows the recovery of oil as a function of pore volume of injected gas. The trend starts to deviate from linearity as the gas injection volume passed over the point of 40 % injection. So breakthrough of the injection gas

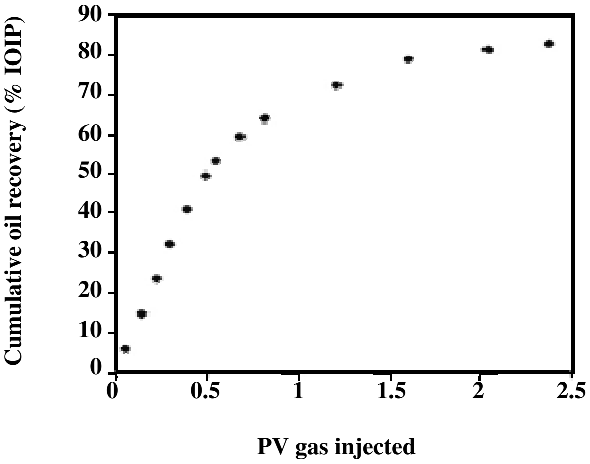

Fig. 11: Oil recovery during gas injection in the physical model.

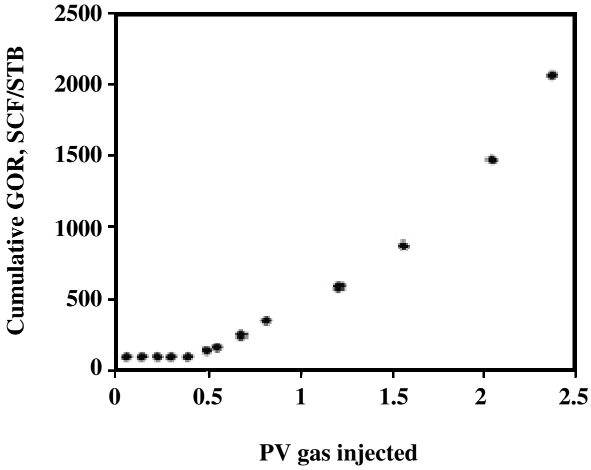

Fig. 12: Gas /oil ratio during gas injection in the physical model.

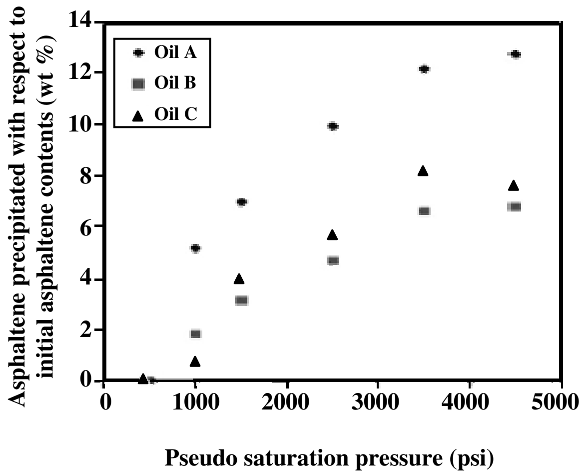

Fig. 13: Precipitated asphaltene as a result of dissolution of Gas A in different oils.

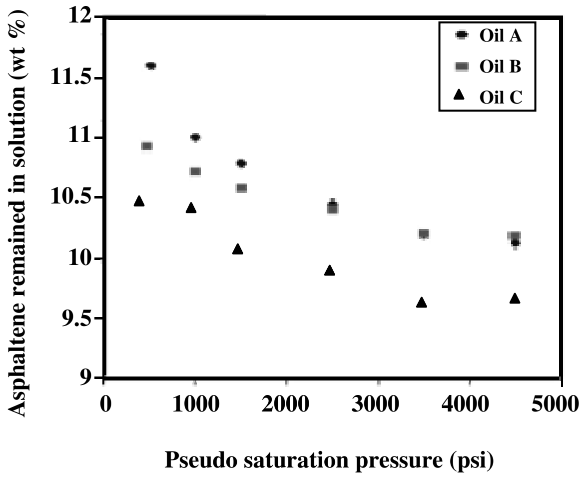

Fig. 14: Remained asphaltene in solution during injecting different volume of Gas A.

occurred at a point between 40 % and 49 % of injected pore volumes. This can be easily recognized from plot of cumulative GOR (Fig. 12) as a point where GOR starts to rise. After breakthrough considerable volume of the oil initially in place was produced, but with the elapse of time the production rate decreased as the slope of cumulative production decreased. Injecting the gas beyond 2.4 PV had negligible effect on oil recovery. High ultimate recovery was obtained (83 %).

Figs. 13 and 14 show the results of asphaltene precipitation tests. Both figures show that as more gas dissolved in the oil more percentage of asphaltene precipitated out of solution. However, in the most severe condition, i.e., highest GORs, less than 15 % of asphaltene initially in solution went out of the oil. This low percentage of precipitation seemed to be promising comparing to high asphaltene contents of test oil. It should be noted that experimental measurements and apparatus could accomplished under up to 5 % laboratory error.

Simulation study was run to inspect the validity of experimental results on field scale. This study confirms the experimental results and recommends gas injection by means of GAGD scenario. The result is that field development based on GAGD, using long horizontal wells would be advantageous and applicable to increase ultimate recovery.

CONCLUSIONS

The following conclusions can be drawn based on the experimental studies:

Swelling tests showed that dissolved gas could considerably change the PVT properties of oil. However, the test gas with higher percentage of sour components had greater effect on changing oil properties than the sweeter one. Sour gas, although, showed better dissolution and more positive effects on viscosity reduction, but further studies should be made on the oil sweetening. This candidate gas can be injected only if an effective and economic sweetening plant can be used.

Experimental results show that gas injection is efficient for reducing the viscosity and reinforces the role of gravity drainage as a drive mechanism. High oil recovery in the physical model showed not only that high recovery values can be obtained from GAGD but also asphaltene precipitation did not show a severe damage for the permeability of porous medium. Because, the possibility of asphaltene precipitation and deposition was closely investigated in PVT cell and was found to be less likely to make a serious problem to gas injection and oil production.

Considering the fact that the contact between oil and gas increases in horizontal wells, simulation study was done on a model consisting horizontal wells. It recommended using of parallel horizontal wells to attain GAGD drive mechanism. This study also showed that higher ultimate oil recovery with higher oil production rates could be expected if the oil viscosity can be reduced with the aid of gas injection in a semi-VAPEX process during gas injection into the oil zone from bottom of the reservoir using long horizontal wells. Simulation study also was carried out to determine the optimum spacing between horizontal wells.

It is noticeable that the difference between calculated recovery factor from simulation and those measured from laboratory investigation is a consequence of discrepancy between small scale of sand pack and huge scale of reservoir.

Nomenclatures

Bo	Oil formation volume factor (FVF), reservoir barrel per stock tank barrel
Pb	Oil bubble point pressure, (psi)
PV	Pore volume (injected fluid volume per volume of pore space, Dimensionless)
Rs	Solution gas oil ratio (standard cubic feet of gas per stock tank barrel of oil)
EOR	Enhanced oil recovery
GAGD	Ggas assisted gravity drainage
GOR	Ggas oil ratio (standard cubic feet of gas per stock tank barrel of oil)
IOIP	Initial oil in place
PVT	Pressure-volume-temperature relation
VAPEX	Vapor extraction

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