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Gas Injection IOR for Widely Varying Initial Compositions

Kameshwar Singh, SPE, PERA and Curtis H. Whitson, SPE, NTNU/PERA

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Abstract

The paper presents the effect of initial reservoir fluid composition on oil recovery for reservoirs under gas injection. To analyze the effect of initial fluid composition, a series of fluid systems were selected based on isothermal gradient calculation from a North Sea field. The systems ranged from low-GOR oils to high-GOR gas condensates, with a continuous transition from gas to oil through a critical mixture.

In this compositional reservoir simulation study, a 3D dipping reservoir with dip angle of 3.8 degree was used. The reservoir layer permeabilities were varied based on Dykstra-Parsons model. Different average reservoir permeability was used to quantify the effect of gravity.

For oil reservoirs, the oil recovery of oil increases with increasing initial solution gas-oil ratio. The oil recovery increases gradually for low-GOR to moderate-GOR oil reservoirs. For moderate-GOR to near-critical oil, the oil recovery increases rapidly. The increase in oil recovery as the reservoir oil becomes more volatile is due to decrease in oil viscosity and the vaporization effects of the injection gas. For gas reservoirs, the condensate recovery increases rapidly from a near-critical gas towards near 100% condensate recovery for high-GOR systems. The oil recovery also depends on the permeability distribution. The oil recovery is higher in the case of high permeability at the bottom than high permeability at the top due to gravity segregation effect. The effect of gravity segregation on oil recovery is more pronounced in high permeability reservoirs. For lean gas condensate the oil recovery is almost independent on the permeability distribution.

The paper shows the variation of oil recovery with initial reservoir fluid composition for different permeability distributions, gas injection period, critical saturation, vertical to horizontal permeability ratio, level of pressure maintenance, and injection gas composition.

Introduction

Recovery mechanisms

Primary recovery is classified by one or more of the following drive mechanisms – internal depletion, gascap expansion, aquifer influx, and compaction. Internal depletion describes the behavior of a single-phase oil or gas fluid system expanding during pressure decline caused by production. Above the initial saturation pressure the expansion is given by the initial system’s total (fluid+pore) compressibility. Below the saturation pressure both gas and oil phase amounts, compressibilities, and mobilities dictate performance. Gascap expansion applies to an oil reservoir containing an overlying gas cap. Production from the oil zone causes pressure drop which in turn causes the gas cap to expand. The expanded gas sweeps into the oil zone and provides pressure support. Water influx from an aquifer reacts to pressure drop from the hydrocarbon reservoir, providing sweep of the hydrocarbons and pressure support.

Gas injection processes are used to enhance the recovery of oil by pressure maintenance. Liquid dropout due to retrograde condensation can be avoided in gas condensate reservoirs by pressure maintenance. Enhanced oil recovery during gas injection can be obtained as a result of swelling of oil, oil viscosity reduction, gravity segregation, vaporization, and miscibility.

In this study, pressure is maintained at the original reservoir pressure by gas injection and oil recovery is obtained from the numerical simulation. It is assumed that the reservoir contains reservoir fluid with constant composition (no compositional gradient in the reservoir). Different reservoir fluids were obtained from isothermal gradient calculations.

Fluid systems

The gas injection performance depends strongly on reservoir fluid properties. Reservoir fluids are classified as black oil, volatile oil, gas condensate, wet gas, and dry gas on the basis of saturation type at reservoir temperature and first stage separator conditions[1,2]. Reservoir fluids can be loosely identified on the basis of initial solution GOR: black oil GOR < 200

Sm^3/Sm^3, volatile oil GOR from 200 to 500 Sm^3/Sm^3, gas condensate GOR from 500 to 2500 Sm^3/Sm^3, wet gas GOR from 2500 to 10,000 Sm^3/Sm^3 and dry gas GOR effectively infinite.

Modeling study

This paper considers only gas injection mechanism of a single-phase hydrocarbon mixture with composition defined by its initial fluid composition. Water influx is ignored. Pore and connate water compressibilities are included but have a negligible effect on most results. A wide range of reservoir fluids has been investigated, with GORs from 22 to 25,000 Sm^3/Sm^3.

A single 6-component equation of state (EOS) model was used with three C_{7+} fractions. A 99-layer dipping 3D cartesian model was used to establish the oil recovery and pressure performance for each fluid. With a 3D model, it was possible to assess the impact of gravity segregation and two-phase near-well flow behavior on well productivity.

PVT data

A fluid sample was selected from a North Sea field[4]. The reservoir is slightly undersaturated with an initial reservoir pressure of 490 bar at the "reference" depth of 4640 m MSL. The selected reference sample contains 8.6 mol-% C_{7+}, it has a two-stage GOR of 1100 Sm^3/Sm^3 and a dewpoint of 452 bar at 163 ^oC. The Pedersen et al. SRK[3] EOS characterization method was used to generate the "base" 22-component EOS model. Decanes-plus was split into 9 fractions.

Because it is impractical to conduct simulations using the 22-component EOS model (due to CPU and memory limitations), several "pseudoized" or reduced-component EOS models were developed – EOS models with 19-, 12-, 10-, 9-, and 6 components. The final 6-component EOS model contained 3 C_{7+} components and 3 C_{6-} components: (N_2,C_1), (CO_2,C_2), (C_3-C_6), (C_7-F2), (F3-8), F9 and is given in Table 1. The 6-component EOS and 22-component EOS model simulated PVT properties were quite close.

Based on isothermal gradient calculations using the 6-component SRK EOS model, the reservoir fluids vary from lean gas condensate to oil in the depth interval from 1000 to 15000 m MSL, with GORs ranging from 22 to 25000 Sm^3/Sm^3, C_{7+} content ranging from 1.0 mol-% at the top to 12.7 mol-% at the near critical to 64 mol-% at the bottom, dewpoints ranging from 155 to 471 bar (maximum), and bubblepoints pressure ranging from 471 to 138 bar. Variations in solution GOR and saturation pressure with depth from the gradient calculation are shown in Fig. 1. The reason for taking the composition from the gradient calculation is to cover a wide range of composition, which can be expected in any field. Fig. 2 shows the variation of saturation pressure with initial solution GOR.

Basic Reservoir and Simulation Model Data

Basic reservoir and fluid properties are given in Table 2. Relative permeabilities[4,5] were taken from a North Sea field and is shown in Fig. 3. The initial water saturation is 26%. The critical gas saturation is 2% and the critical oil saturation (to gas) is 22.7%.

To describe the layered reservoir performance, a reservoir with 99 numerical layers, each with an equal vertical thickness of 1.51 m (total thickness 150 m) is used. The length and width of the reservoir are 3000 m and 1000 m respectively. The permeability variation is described by Dykstra-Parsons coefficient of 0.75. The average permeability of the reservoir is 232 md with a maximum layer permeability of 2500 md and a minimum layer permeability of 4 md (ratio of highest to lowest k is 633). The reservoir is described by 15x5x99 grid cells and is shown in Fig. 4. The dip of the reservoir considered is 3.8 degrees. In all simulation cases, the initial reservoir pressure is 495 bar at a reference depth of 4750 m. In this study, all compositional reservoir simulation study[6,7,8,9] was done using a commercial numerical reservoir simulator[10].

The reservoir is produced through one well on maximum withdrawal constraint (about 10% hydrocarbon pore volume per year) with minimum well bottom hole pressure of 300 bar. The producer is located in the last grid cell (15,5) and perforated in all numerical layers (1-99). The injector is placed in the first grid cell (1,1) and completed in all layers. Lean gas is injected to maintain the reservoir pressure equal to the initial reservoir pressure. The reservoir performance is compared for 15 years i.e. after injection of 1.5 pore volume (PV) of injection gas. The composition of the lean injection gas in mol-% is 84.6 (C_1N_2), 9.65 (CO_2C_2), 5.57 (C_{3-6}), and 0.18 ($C_{7-9}F_{1-2}$).

Minimum miscibility pressure

Oil recovery by gas injection depends on minimum miscible pressure. Minimum miscibility pressure (MMP) is the lowest pressure when injection gas can displace reservoir fluid miscibly. The dispersion free oil recovery is 100% when reservoir pressure is equal or above the MMP. In this study, a PVT program PhazeComp[11] was used for MMP calculation and the calculated MMP is plotted in Fig. 5. The reservoir pressure is 495 bar at a reference depth of 4750 m. The MMP for the oil system is higher than the reservoir pressure (except for the near critical oil where the MMP is slightly lower than the reservoir pressure). For gas systems, the MMP is equal to the saturation pressure of the reservoir fluid.

Simulated Performance Analysis

The 99-layer simulation model was used to evaluate the oil recovery for different fluids. The reservoir was initialized with constant composition thorough out the reservoir. Lean gas was injected to maintain the initial reservoir pressure of 495 bar. The oil recovery factor is defined as the ratio of difference in initial fluid in place (i.e. initial fluid in place - fluid in place at the end of the simulation) to initial fluid in place. In case of the reservoir gas system, the "oil" recovery is condensate recovery. The variation of initial oil in place (IOIP) vs initial solution GOR is, of course, significant. Reserves are obtained by multiplying IOIP by recovery factor. Fig. 6 shows IOIP (per HCPV) which represents an "inverse oil formation volume factor (b_{oi}=1/B_{oi}) vs initial solution GOR; all simulations have the same HCPV.

3D model with the highest permeability at the bottom

The base simulation model is the 99-layer case with the highest permeability at the bottom of the reservoir. First the reservoir was simulated for oil system with an initial solution GOR of 22 Sm^3/Sm^3. Oil recovery factor in this case was equal to 44.0%. The reservoir was also simulated with other fluid compositions. Simulated oil recovery factor versus initial solution GOR for different fluids is plotted in Fig. 7 (though the oil recovery is plotted against initial solution GOR, the compositional simulation model was initialized with reservoir fluid composition in mole fraction). The recovery of oil increases with increasing initial solution GOR and reaches a maximum value of 66.8% for the near-critical oil.

The increase in oil recovery as the reservoir oil becomes more volatile is due to decrease in oil viscosity and the vaporization effects of the injection gas. These effects are more effective than the effect of the reduced density difference between the injection gas and the reservoir fluid.

For gas reservoirs, oil recovery was 66.8 % for the near critical fluid with initial solution GOR of 625 Sm^3/Sm^3. Recovery factors are plotted in Fig. 7 for gas reservoirs with different initial solution GOR. As the fluid gets leaner, the oil recovery decreases in the case of high permeability at the bottom. This is because the density difference between the reservoir fluid and the injection gas decreases. For the lean gas condensates the recovery factor increases monotonically with increasing initial solution GOR and is about 90% for the leanest gas condensate.

Effect of amount of gas injection

In the base case, oil recovery was estimated after 1.5 PV of gas injection. Sensitivity cases were run to evaluate the effect of amount of gas injection on the oil recovery. All above cases were rerun for 50 years (5 PV) and the simulated oil recovery is shown in Fig. 8 for different fluids. Oil recovery was increased (both for oil reservoirs and gas reservoirs) when 5 PV of gas was injected. The oil recovery was almost 100% for the lean gas condensate fluids.

Effect of critical gas saturation

In the base case, critical gas saturation was 2%. Sensitivity cases were run to evaluate the effect of critical gas saturation on the oil recovery. The critical gas saturation was increased to 10% using end point scaling option in the simulator. The simulated oil recovery for different fluids is shown in Fig. 9. In another case, the critical gas saturation was further increased to 20%. For the oil system, the oil recovery decreases with increasing critical gas saturation. For the gas system, critical gas saturation has no effect on oil recovery.

Effect of critical oil saturation

In the base case, critical oil saturation was 22.7%. Sensitivity cases were run to evaluate the effect of critical oil saturation on the oil recovery. The critical oil saturation was decreased to 10% using end point scaling option in the simulator. The simulated oil recovery for different fluids is shown in Fig. 10. The oil recovery increases with decreasing critical oil saturation for the oil system. For the gas system, critical oil saturation has no effect on oil recovery if reservoir pressure is maintained at a pressure higher than the initial saturation pressure of the fluid.

Effect of average reservoir permeability

To evaluate the effect of average reservoir permeability on the oil recovery, the average reservoir permeability was changed from 232 md (in the base case) to 50 md. The oil recovery for different fluids is shown in Fig. 11. The oil recovery is lower in the case of lower average reservoir permeability. In case of lower average reservoir permeability, the gas segregation is less thus oil recovery is also lower. The oil recovery for the near critical fluid was 66.8% in the case of average reservoir permeability of 232 md and 52.2% in the case of average reservoir permeability of 50 md. The decrease in oil recovery is more pronounced for low-GOR oils. For lean gas condensate fluids, the oil recovery is slightly lower.

Effect of permeability distribution

To evaluate the effect of permeability distribution on the oil recovery, the permeability distribution in the base case was changed. The highest permeability layer was used as numerical layer one (top layer); next highest permeability layer as numerical layer two and so on. The bottom numerical layer has the lowest permeability. The reservoir with new permeability distribution was simulated with different fluids. The oil recovery for different fluid is shown in Fig. 12.

The oil recovery was lower in the case of the highest permeability at the top than the case with the highest permeability at the bottom as shown in Fig. 12. Oil recovery for the near critical fluid was 66.8% in the case of the highest permeability at the bottom and 51.7% in the case of the highest permeability at the top. In the case of the highest permeability at the bottom, the injection gas segregates upward. In the case of the highest permeability at the top, the segregated injection gas is produced through the high permeability top layer. For the leanest gas condensate, the oil recovery is almost independent on the permeability distribution.

The effect that gravity has on the production performance is very dependent on average reservoir permeability as shown in Fig. 13. In the case of high average reservoir permeability, the effect of gravity is more and there is more gas segregation. In case of lower reservoir permeability, the gravity effect is lower.

Effect of vertical permeability

Gas injection efficiency depends on vertical sweep efficiency. To evaluate the effect of vertical sweep efficiency, the vertical permeability was changed. In the base case, the ratio of vertical to horizontal permeability was 0.1. Two sensitivities cases were simulated i.e. one by increasing the ratio to 0.5 and another by decreasing the ratio to 0. The simulated oil recovery is shown in Fig. 14. After increasing the vertical permeability, the oil recovery increases significantly due to better vertical sweep efficiency. Similarly after decreasing the vertical permeability to zero i.e. no layer cross flow, the oil recovery decreases.

For the case with the highest permeability at the top, the effect of vertical to horizontal permeability ratio is negligible. The oil recovery increases slightly after decreasing the vertical permeability as shown in Fig. 15.

Effect of injection gas composition

In the base case, the lean gas was injected. A sensitivity case was simulated where methane gas was injected to maintain the initial reservoir pressure. The simulated oil recovery is shown in Fig. 16. For the reservoir oil system, the oil recovery is slightly lower in the methane gas injection case. But for the reservoir gas system, the oil recovery is higher for methane injection case compared to lean gas injection case. This is due to more vaporization effect of the methane in the reservoir gas system.

Effect of reservoir pressure maintenance at lower pressure

In the base case, the reservoir pressure was maintained at the initial reservoir pressure of 495 bar. Sensitivity cases were simulated where the reservoir pressure was maintained at the saturation pressure (Fig. 2) of the initial reservoir fluid. Thus the reservoir pressure was maintained at different pressure (equal to initial saturation pressure of the fluid) in different simulated cases. Since the saturation pressure of the low-GOR oil is about 138 bar, the well BHP was reduced from 300 bar to 100 bar in these sensitivity cases. The simulated oil recovery is shown in Fig. 17. The oil recovery is lower for the volatile oil to the rich gas condensate reservoirs. For the lean gas condensate, the oil recovery is slightly higher. For the low-GOR oils, the oil recovery is quite low since the reservoir pressure is maintained at lower pressure.

Effect of well completion

To evaluate the effect of well completion, well completion was changed. In the base case, the vertical producer and the vertical injector were completed in all numerical layers. A sensitivity case was simulated where the injector was completed in the upper half of the reservoir (numerical layers 1-50) and the producer was completed in the lower half of the reservoir (numerical layers 51-99). The oil recovery was slightly higher in this case than in the base case as shown in figure Fig. 18.

Effect of dip angle

In the base case, a dip angle of 3.8 degree was used. A sensitivity case was simulated assuming all layers as horizontal (i.e. reducing the dip angle to zero). The simulated oil recovery is shown in Fig. 19. The simulated oil recovery decreases slightly for both oil and gas system.

Effect of number of vertical layers

Since it is impractical to simulate the full-field simulation model with large number of numerical layers (e.g. 99 layers) due to CPU and memory limitations, the number of numerical layers was reduced from 99 to 10. In the 10-layer simulation case, the number of layer was reduced such that each layer has same flow contribution (initially) i.e. the lowest layer with the highest permeability will have the lowest thickness (permeability thickness product was same for all 10 layers). In the 10-layer case, the average reservoir permeability was same as in the base (99 layer) case. The simulated oil recovery is shown in Fig. 20. For the gas system, the oil recovery is almost same as in the base case. For the oil system, the oil recovery increases due to more gravity segregation of the injection gas in the 10-layer cases.

Depletion performance

The main objective of gas cycling is to improve the recovery over depletion. To quantify the improvement in oil recovery under gas cycling, the reservoir was simulated under depletion. The minimum well bottom hole pressure was reduced to 100 bar in all depletion cases. Fig. 21 shows the simulated oil recovery for different fluids under depletion. As shown in the figure, there is significant improvement in oil recovery under gas cycling over depletion. The difference in oil recovery is more for the volatile oil and rich gas condensate.

The reservoir with the highest permeability at the top was also simulated under depletion and the simulated oil recovery is shown in Fig. 22. In the case of the highest permeability at the top, the oil recovery is quite similar (gas cycling versus depletion) for the low GOR oil and lean gas condensate. For high-GOR oil to rich gas condensate, there is significant difference in oil recovery between gas cycling and depletion. For gas reservoirs, the depletion oil recovery is same in the highest permeability at the top and in the highest permeability at the bottom cases.

Conclusions

This study provides general gas injection performance behavior for a wide range of reservoir fluids from black oil through critical mixtures to lean gas condensates for a multi-layered reservoir with cross flow. The reservoir is considered a single geologic unit without flow barriers; water influx is ignored.

1. For oil reservoirs the recovery of oil increases slowly with increasing initial solution GOR until a moderate GOR of about 200 Sm^3/Sm^3 where a recovery level of 50% was reached. At higher GORs the oil recovery increases rapidly towards a maximum value of about 67% at the GOR of 625 Sm^3/Sm^3 where the fluid becomes critical and transitions into a gas system.
2. For gas reservoirs the condensate recovery increases from about 67% for the near-critical gas system with 625 Sm^3/Sm^3 GOR towards very high recoveries (approaching gas recovery factors) for very-lean high-GOR systems.
3. Oil recovery increases with increasing amount of gas injection for both oil system and gas system. The oil recovery for the oil system is also influenced by the critical gas saturation and critical oil saturation. In case of lower critical oil saturation, oil recovery increases for the oil system. For oil system, oil recovery decreases with increasing critical gas saturation.
4. For low permeability reservoir, the oil recovery is lower due to less gas segregation for both oil and gas systems. For the lean gas condensate, the oil recovery is almost independent of the average reservoir permeability.
5. The oil recovery depends on the permeability distribution. The oil recovery is higher in case of high permeability at the bottom than high permeability at the top due to gravity segregation effect.
6. The effect of gravity segregation on oil recovery is more pronounced in case of high average reservoir permeability.

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Tables

Table 1 — Parameters for the 6-component SRK EOS fluid model.

Component	MW	Critical Temperature	Critical Pressure	Acentric Factor	Critical Volume	Boiling Point	
	M	T_C	P_C	ω	V_C	T_b	
		K	bar		m^3/kmol	K	
C_1N_2	16.1	190.3	45.9	0.01	0.0990	111.4	
CO_2C_2	35.4	304.8	60.8	0.16	0.1208	189.4	
$C_{3\text{-}6}$	55.1	418.9	37.8	0.20	0.2601	269.6	
$C_{7\text{-}9}$F1-2	116.9	577.4	28.4	0.54	0.5117	420.4	
F3-8	281.0	753.3	15.2	0.97	1.1163	626.7	
F9	621.6	979.3	12.1	1.32	2.5673	829.6	
Component	Specific Gravity	Volume Shift	BIPS	BIPS	OmegaA	OmegaB	Parachor
	γ	s	$k_{C1N2\text{-}I}$	$k_{CO2C2\text{-}I}$	Ω_a	Ω_b	P
C_1N_2	0.3305	0.023			0.4269	0.09	77
CO_2C_2	0.4757	0.067	0.05735		0.4440	0.0915	93
$C_{3\text{-}6}$	0.5630	0.099	0.00041	0.05749	0.4208	0.0837	181
$C_{7\text{-}9}$F1-2	0.7864	0.109	0.00027	0.04791	0.4225	0.0894	379
F3-8	0.8576	0.118	0.00027	0.04791	0.4141	0.0827	732
F9	0.9136	-0.134	0.00027	0.04791	0.4275	0.0866	1169

Table 2 — Reservoir and Rock Properties

Absolute Horizontal permeability, md	232
Vertical/Horizontal permeability ratio	0.1
Dykstra-Parsons coefficient	0.75
Porosity, %	15
Reservoir Height, m	150
Rock Compressibility, bar^{-1}	4.00E-5
Irreducible Water Saturation, %	26
Initial Reservoir Pressure, bar at 4750 m	494.68
Initial Reservoir Temperature, ^oC	163
Critical Gas Saturation, %	2.0
Critical Oil Saturation, %	22.7
Residual Oil Saturation, %	21.5

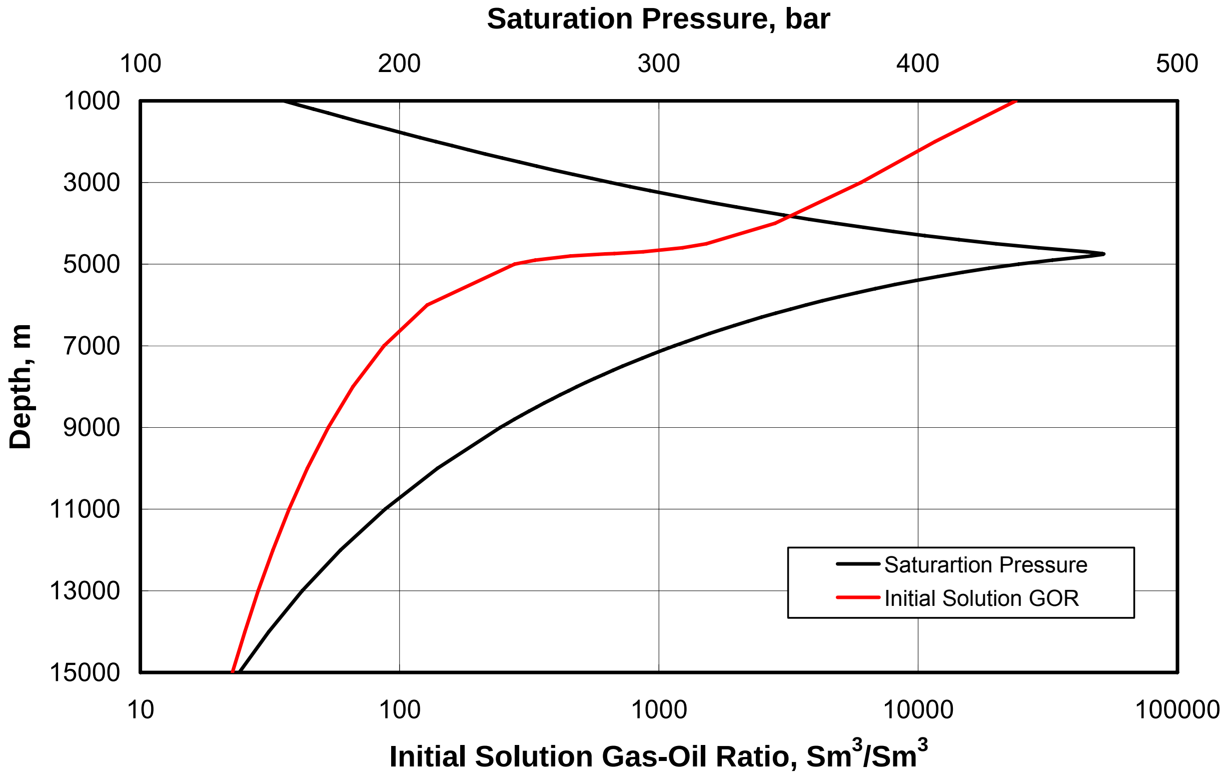

Fig. 1 — Initial solution gas-oil ratio (GOR) and saturation pressure variation with depth for different fluid system.

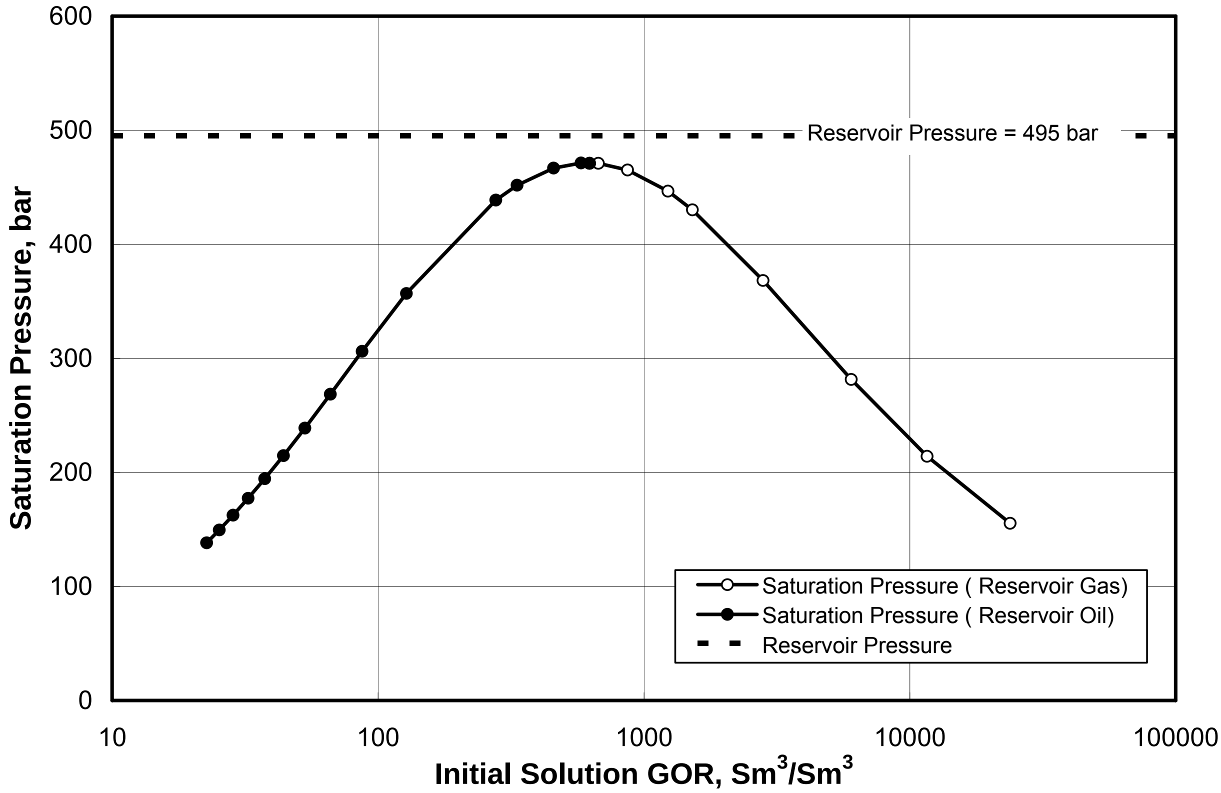

Fig. 2 — Saturation pressure variation with initial solution GOR for different fluid system.

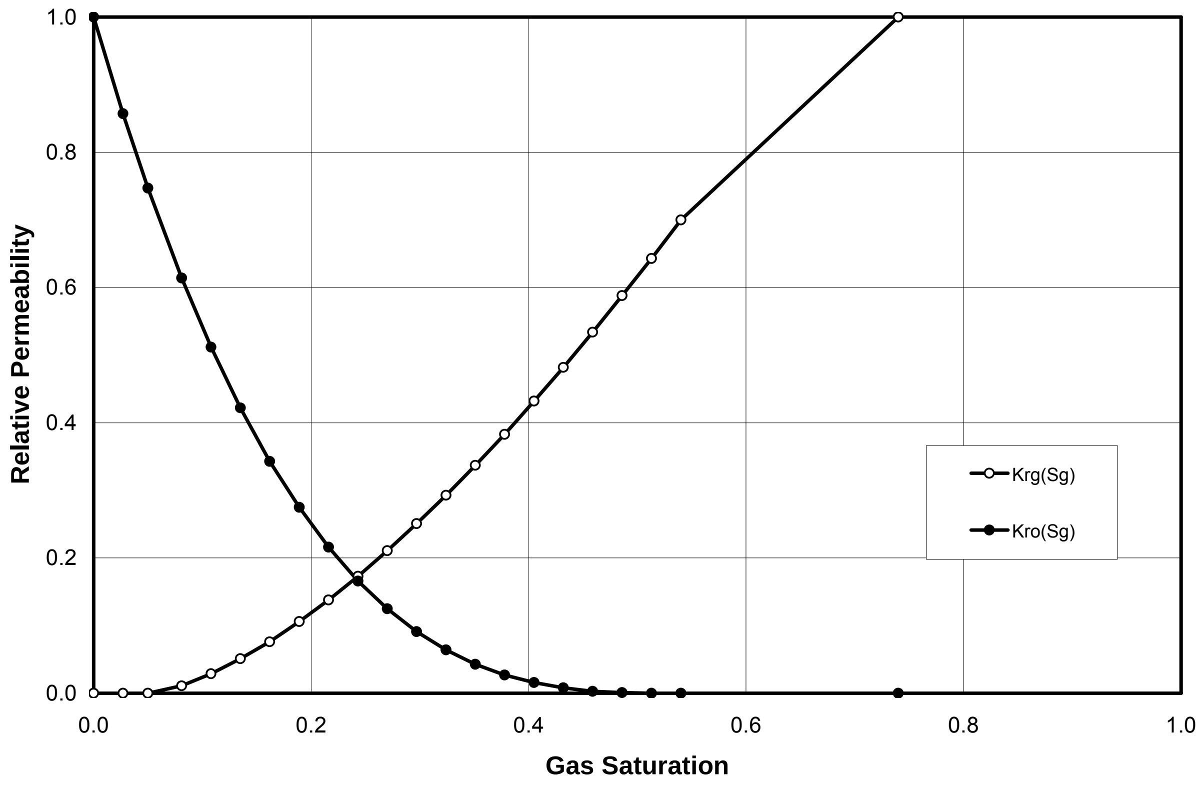

Fig. 3 — Oil and gas relative permeabilities.

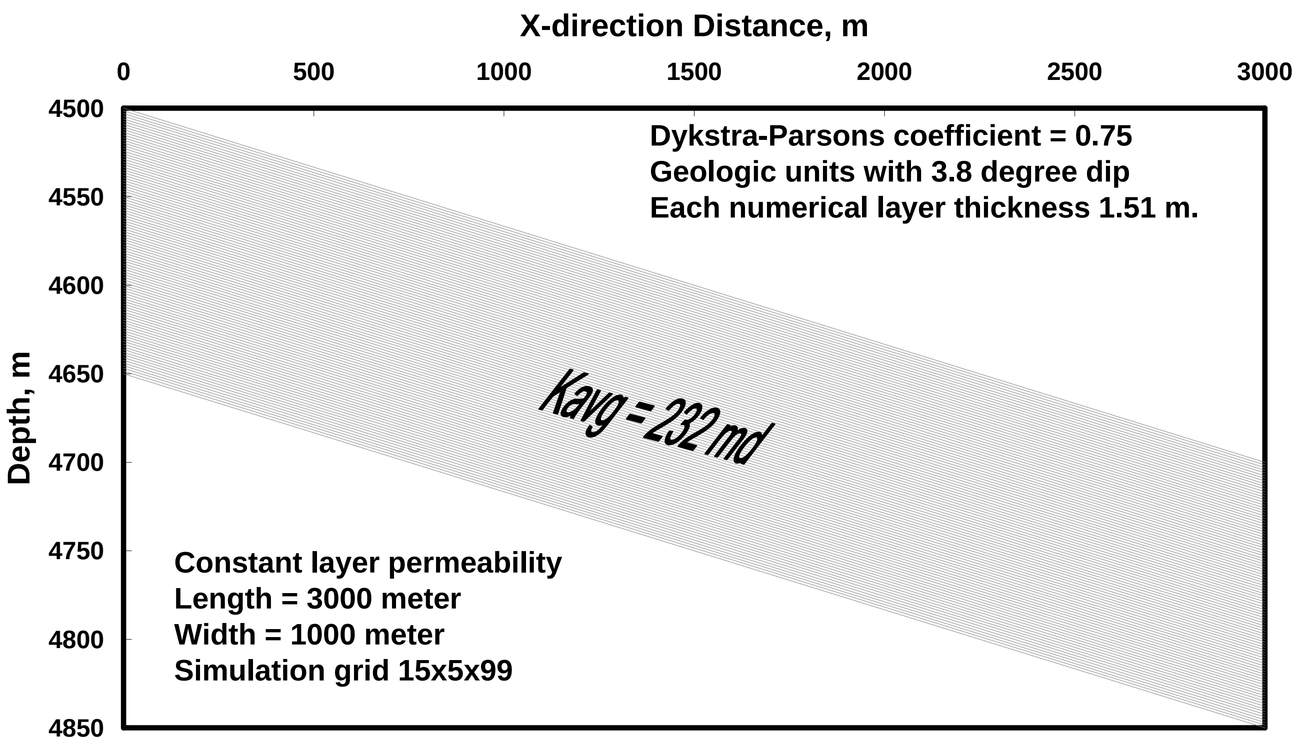

Fig. 4 — 3D 99-layers dipping reservoir simulation model. Thickness of each layer is 1.51 m. Permeability of different layers is different (in the base case, the permeability is 2500 md for the bottom layer and 4 md for the top layer).

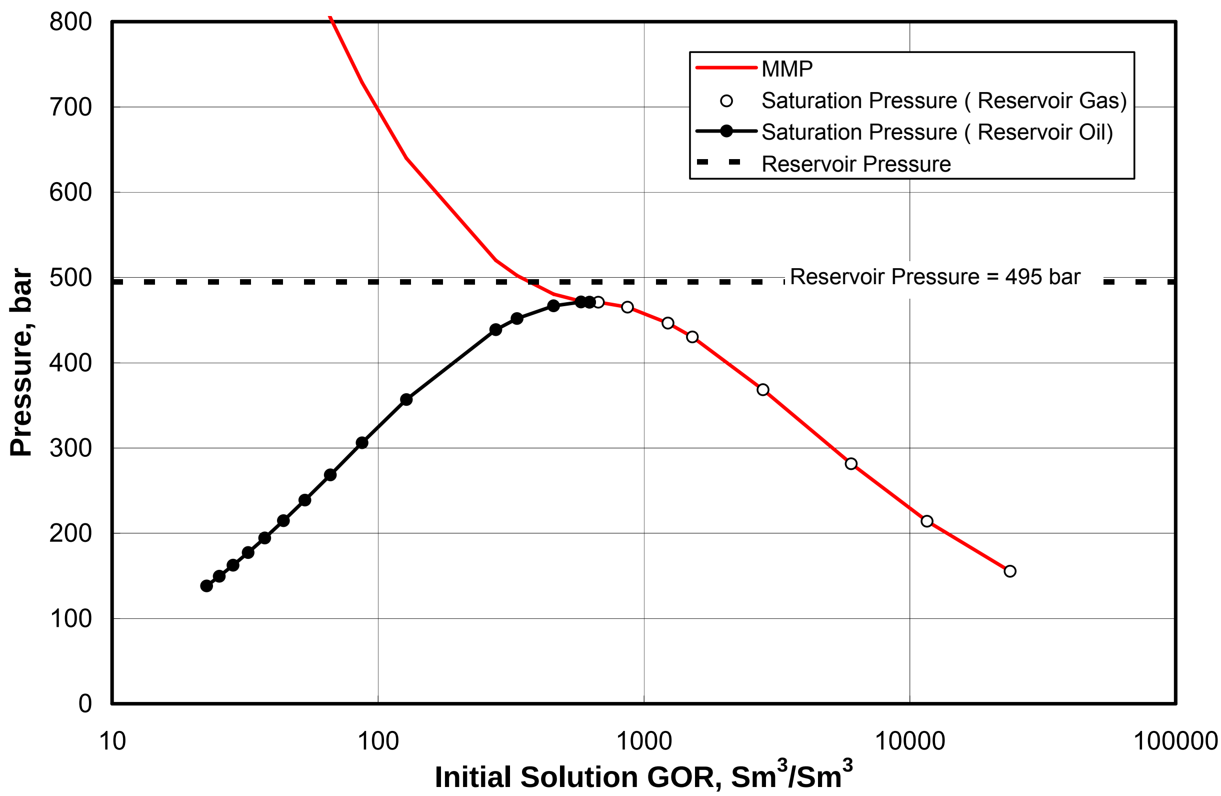

Fig. 5 — Calculated minimum miscibility (with lean injection gas) pressures for different fluid systems. The MMP of the reservoir gas system is equal to the dewpoint pressure of the gas. For oil system, the MMP is higher than the bubblepoint pressure of the oil.

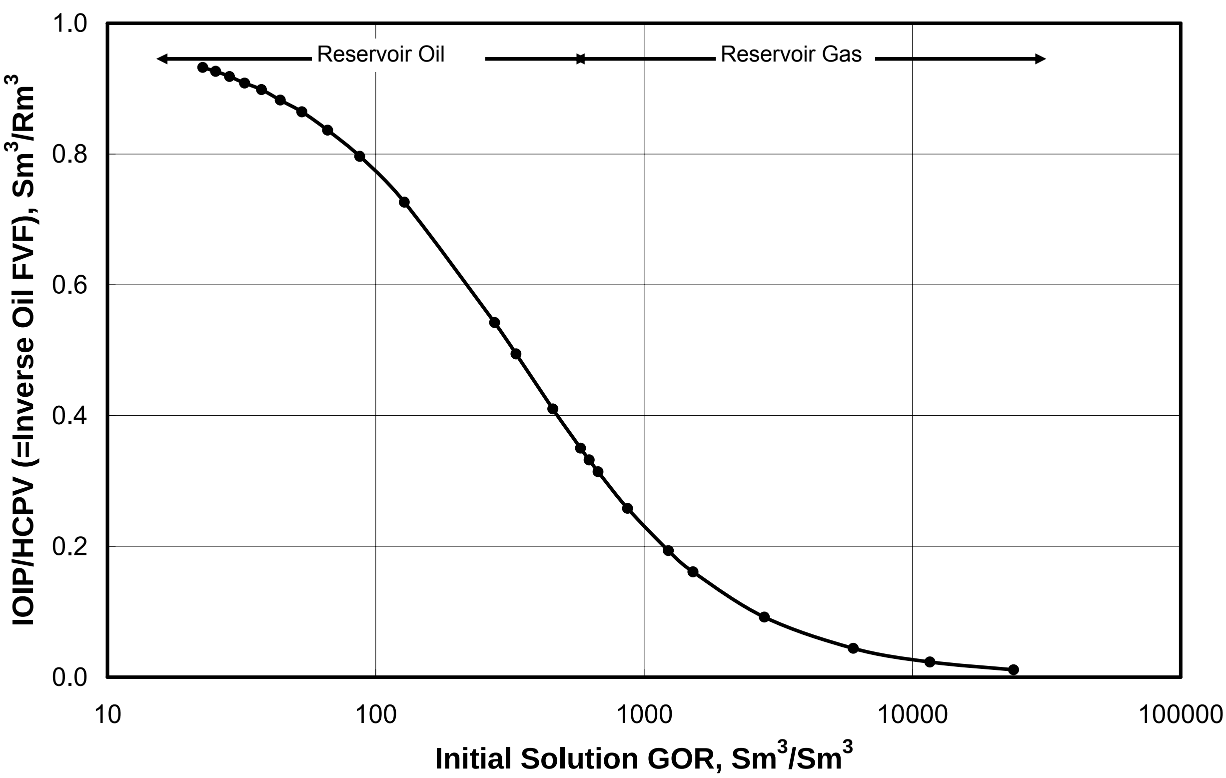

Fig. 6 — Initial oil in place with initial solution gas-oil ratio for different fluids.

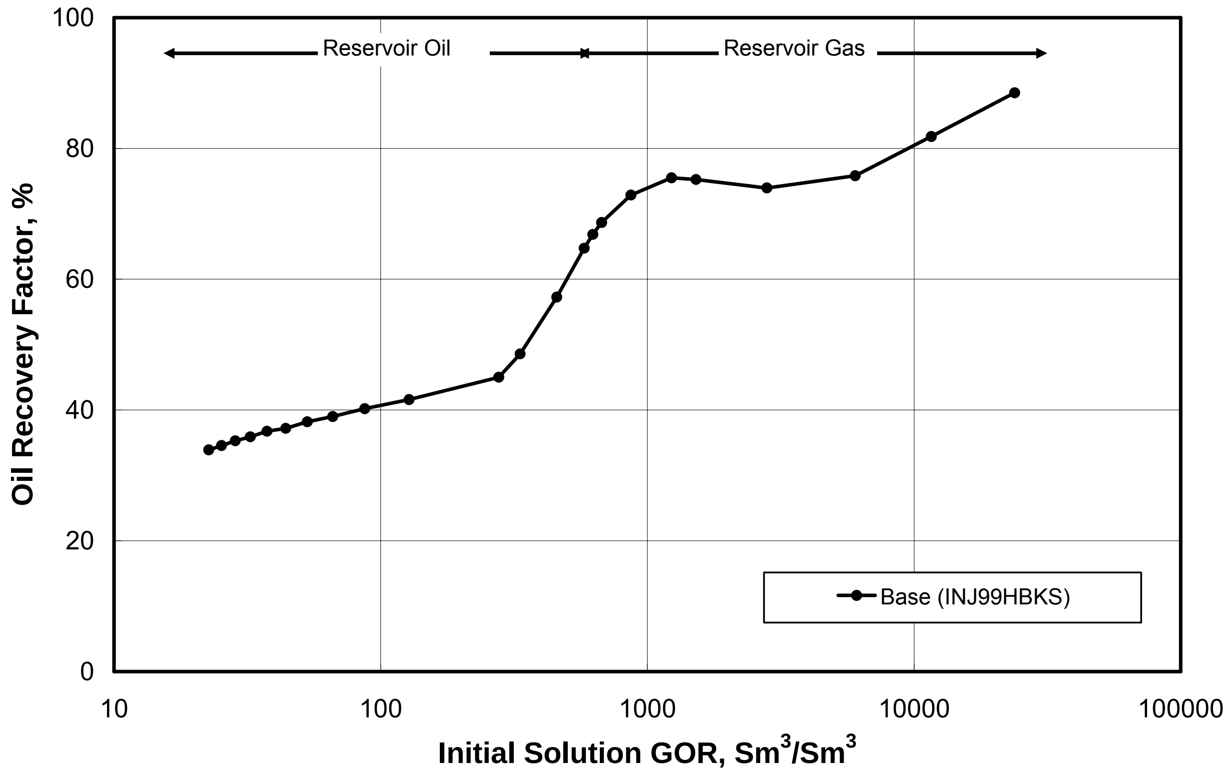

Fig. 7 — Oil recovery in the base case (99-layer case with the highest permeability at the bottom; lean gas injection to maintain the reservoir pressure at the initial reservoir pressure; injection period 15 years i.e. 1.5 PV gas injection; average reservoir permeability equal to 232 md).

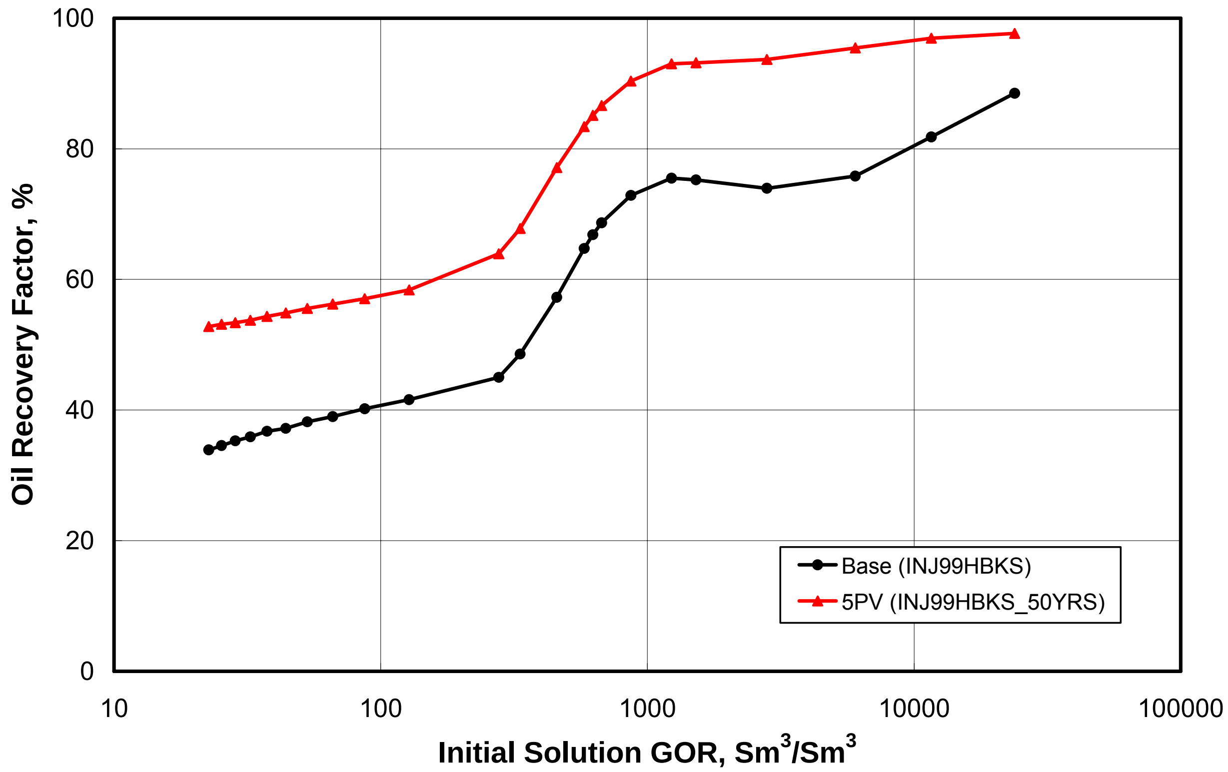

Fig. 8 — Effect of amount of gas injection on the oil recovery – (a) base case: the reservoir was simulated for 15 years i.e. 1.5 PV gas injection (b) sensitivity case: the reservoir was simulated for 50 years i.e. 5 PV gas injection.

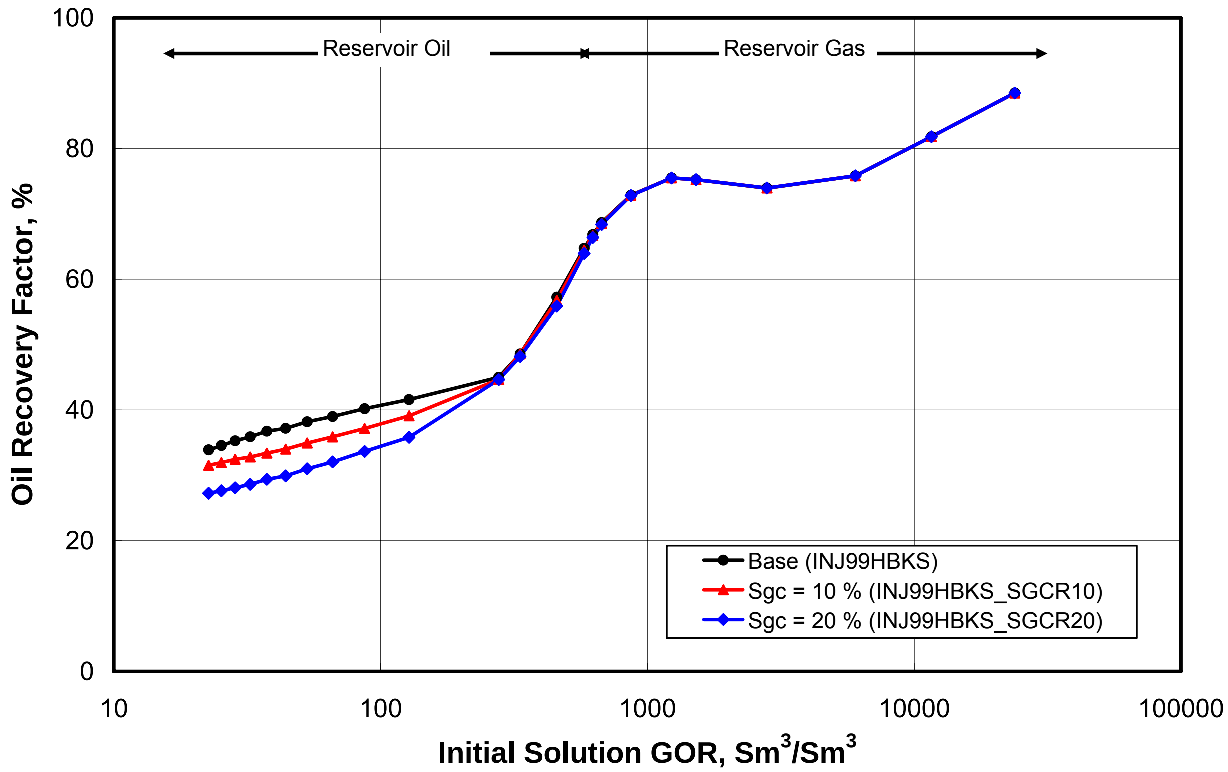

Fig. 9 — Effect of critical gas saturation on the oil recovery – (a) base case: the critical gas saturation is 2% (b) sensitivity cases: the critical gas saturations are 10- and 20-%.

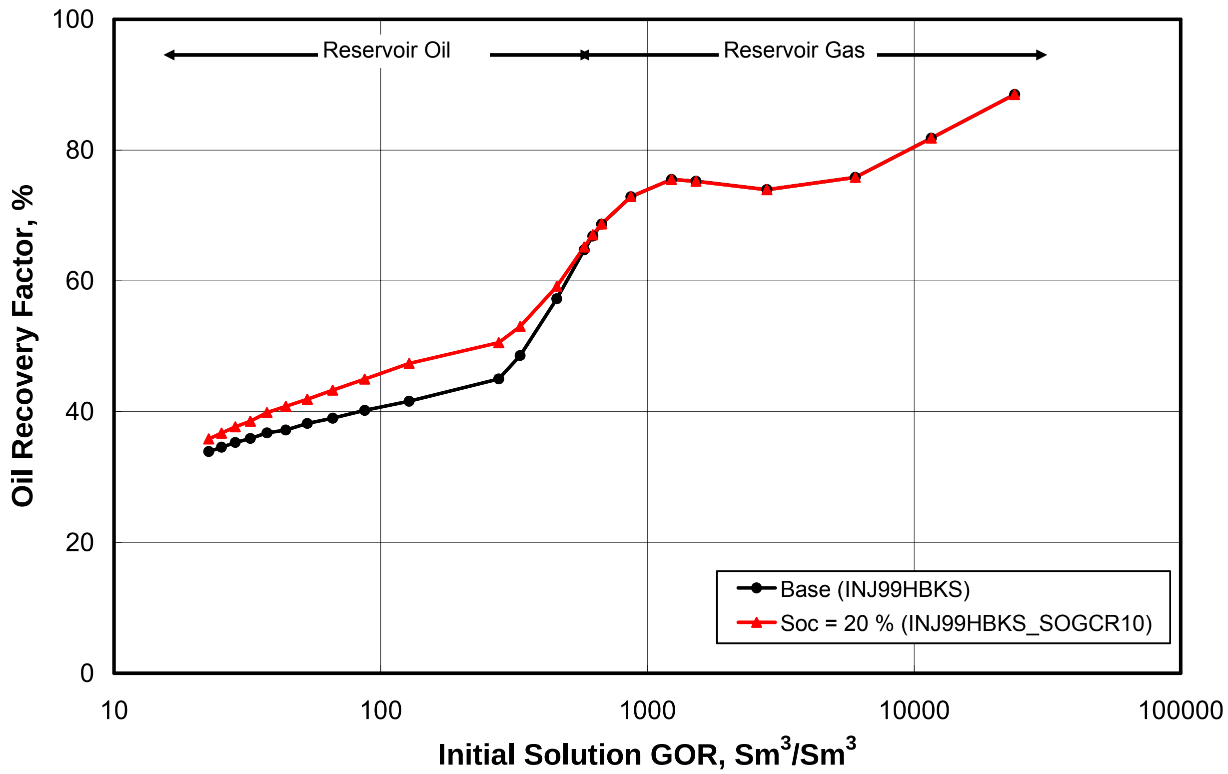

Fig. 10 — Effect of critical oil saturation on the oil recovery – (a) base case: the critical gas saturation is 22% (b) sensitivity case: the critical gas saturation is 10%.

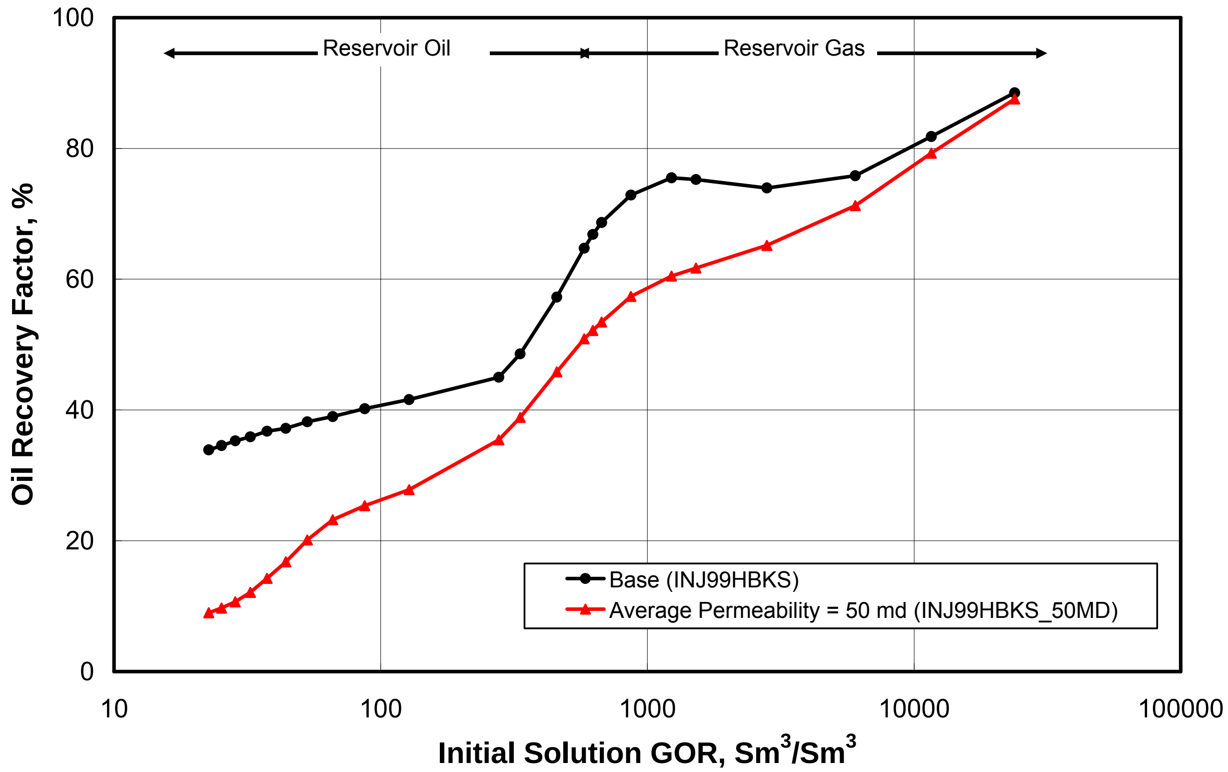

Fig. 11 — **Effect of average reservoir permeability on the oil recovery – (a) base case: the average reservoir permeability is 232 md (b) sensitivity case: the average reservoir permeability is 50 md.**

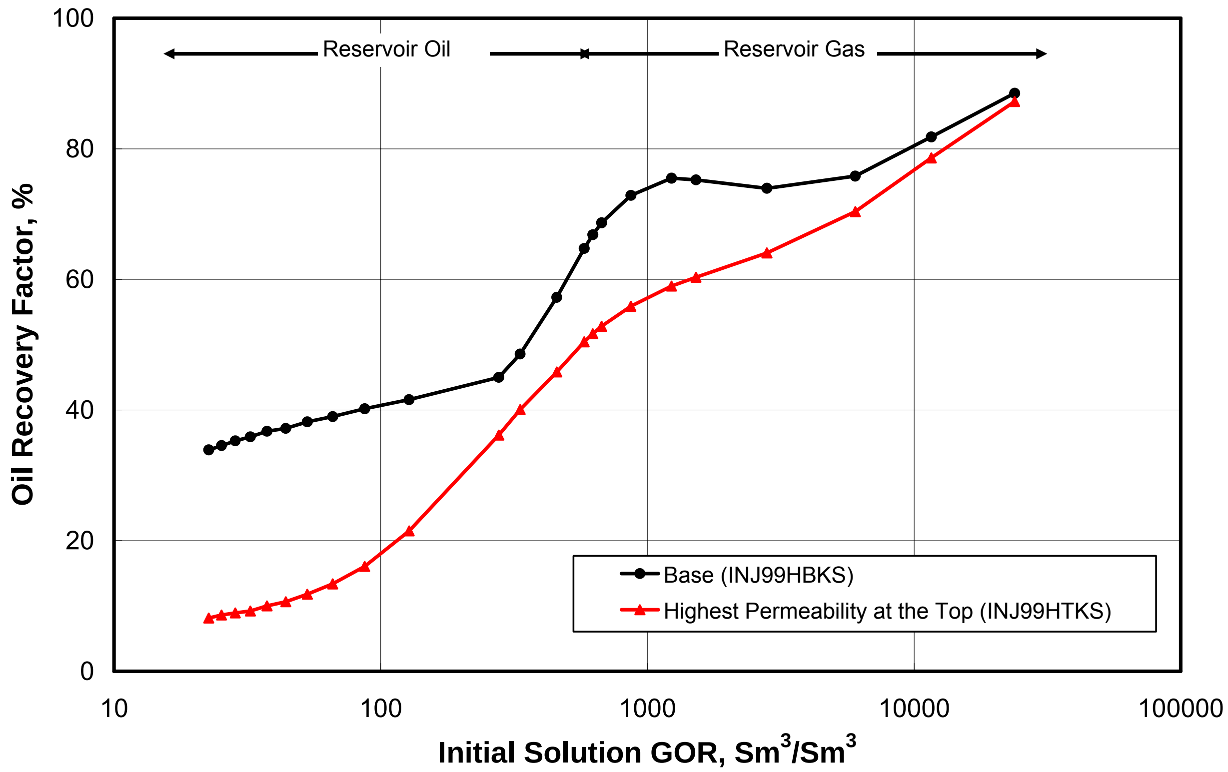

Fig. 12 — **Effect of permeability distribution on the oil recovery – (a) base case: the highest permeability is at the bottom (b) sensitivity case: the highest permeability is at the top.**

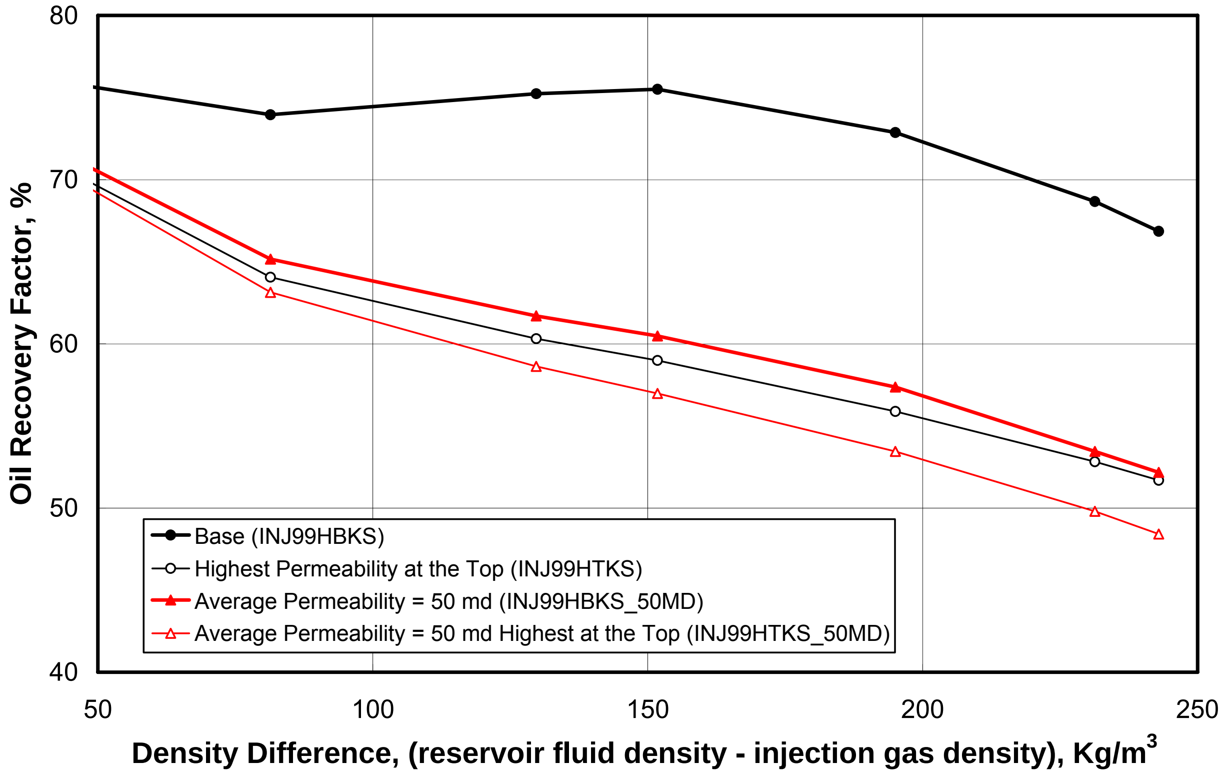

Fig. 13 — Oil recovery variation with average reservoir permeability (a) the highest permeability at the bottom (b) the highest permeability at the top.

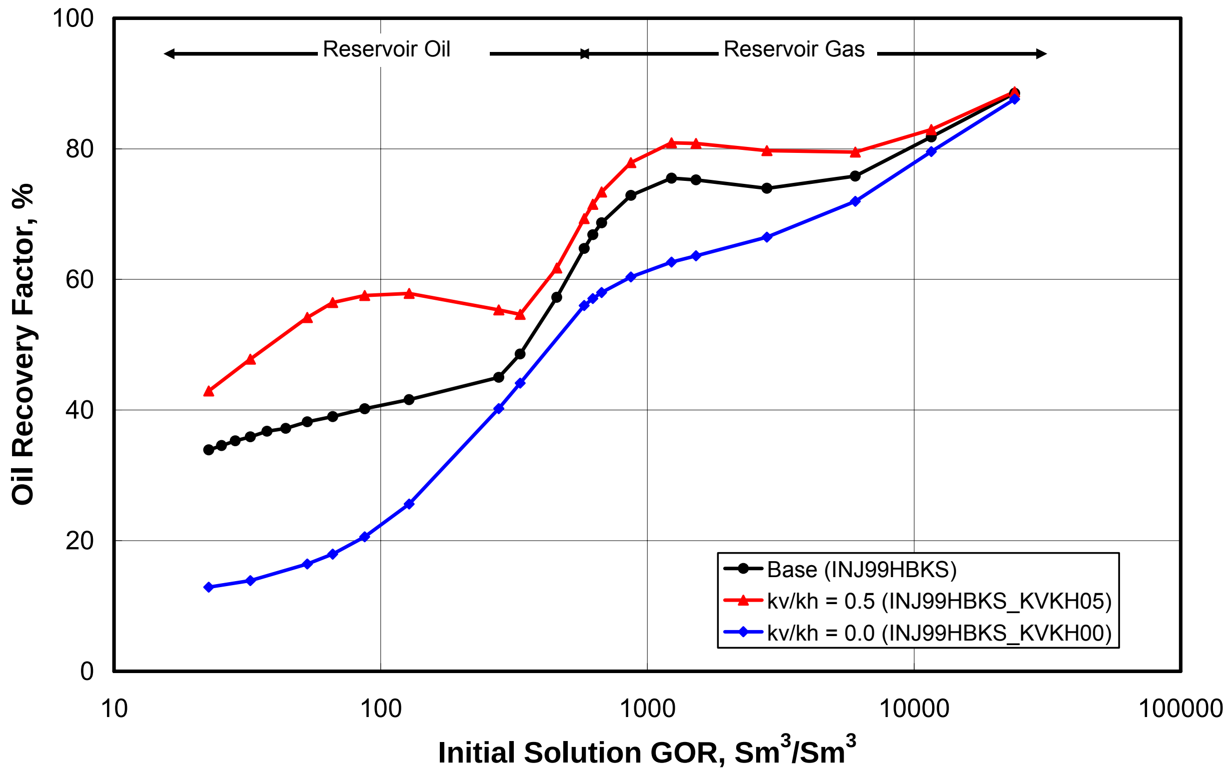

Fig. 14 — Effect of vertical/horizontal permeability ratio on the oil recovery – (a) base case: k_v/k_h= 0.1 (b) sensitivity cases: k_v/k_h =0.5 and 0.0.

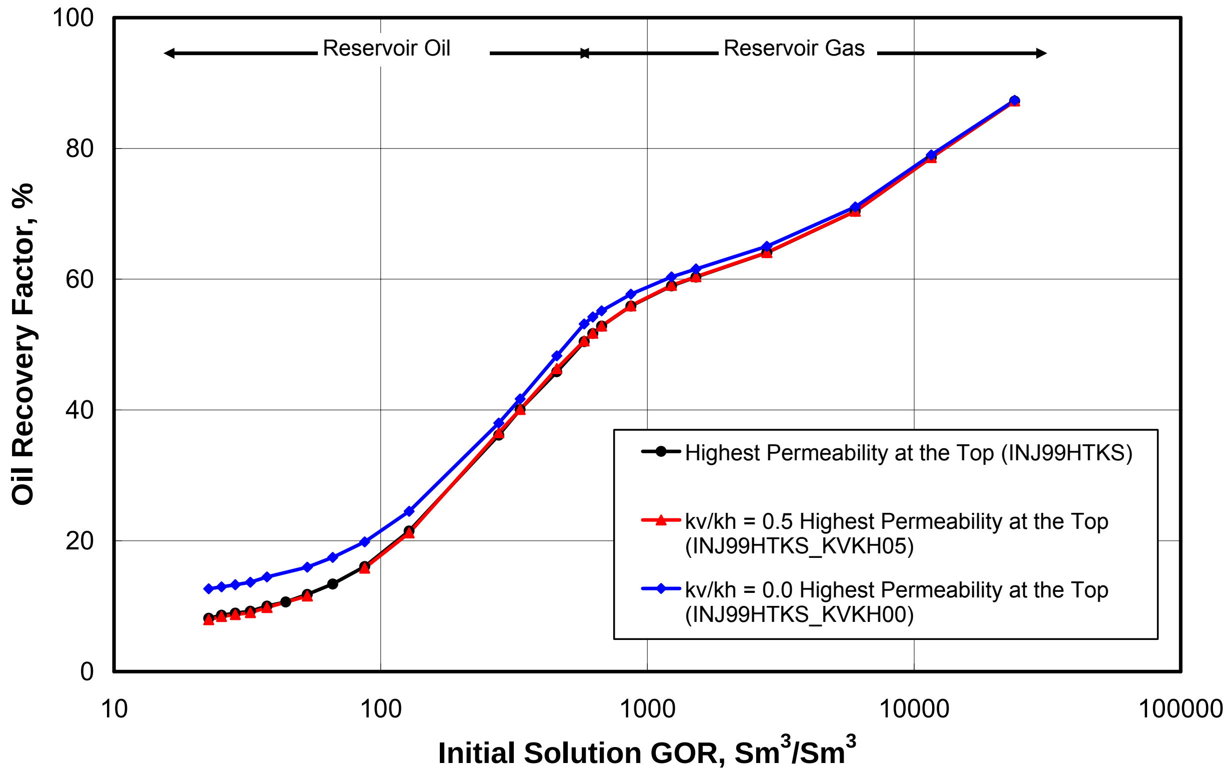

Fig. 15 — **Effect of vertical/horizontal permeability ratio on the oil recovery in case of the highest permeability at the top – (a) base case: k_v/k_h= 0.1 (b) sensitivity cases: k_v/k_h =0.5 and 0.0.**

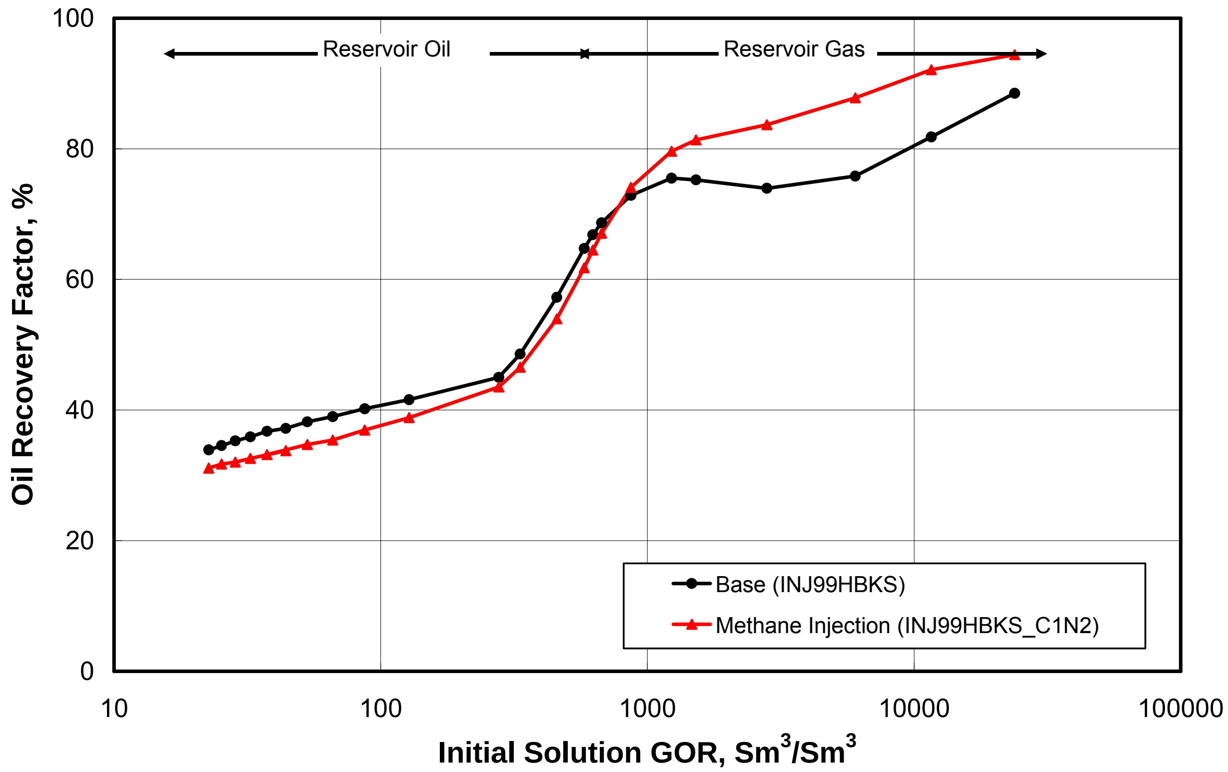

Fig. 16 — **Effect of injection gas composition on the oil recovery – (a) base case: lean gas injection (b) sensitivity case: methane gas injection.**

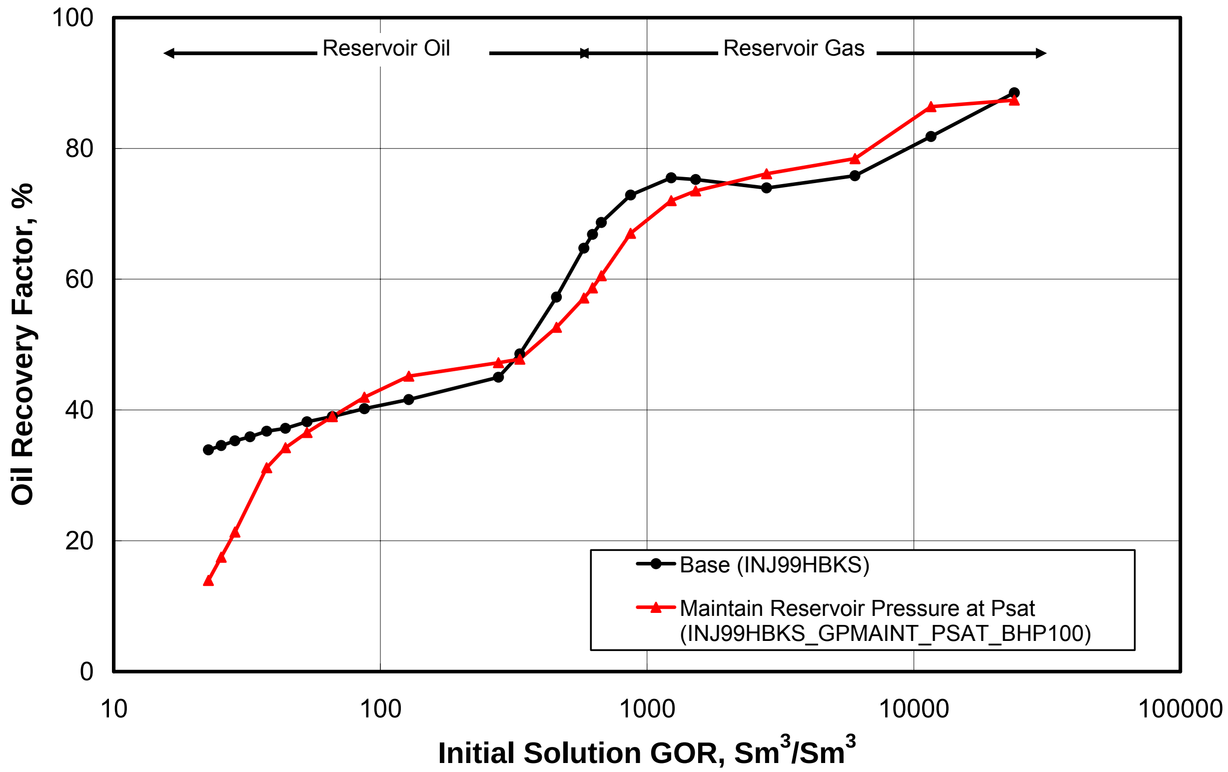

Fig. 17 — Effect of pressure maintenance at lower pressure – (a) base case: the reservoir pressure is maintained at the initial reservoir pressure (b) sensitivity case: the reservoir pressure is maintained at the saturation pressure of the initial reservoir fluid.

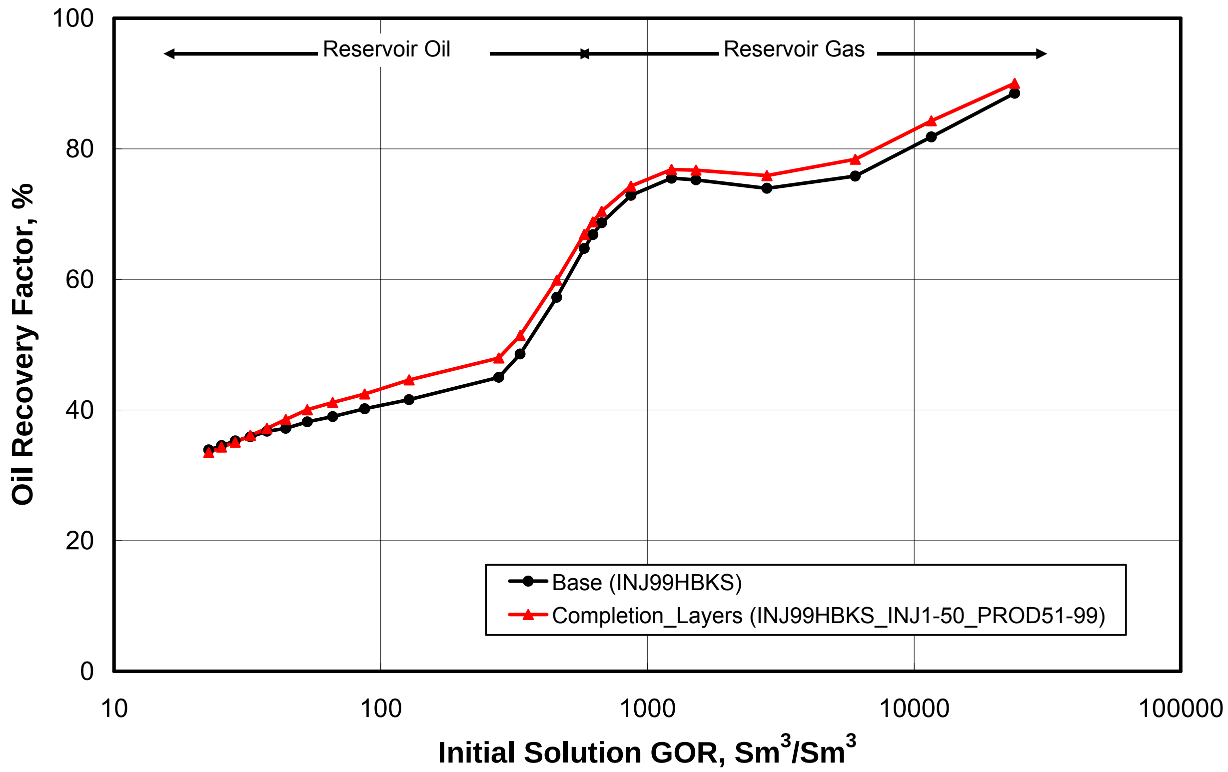

Fig. 18 — Effect of well completion on the oil recovery – (a) base case: the producer and the injector are completed in all layers (b) sensitivity case: the injector is completed in the upper half (numerical layer 1-50) and the producer is completed in the lower half (numerical layer 51-99) of the reservoir.

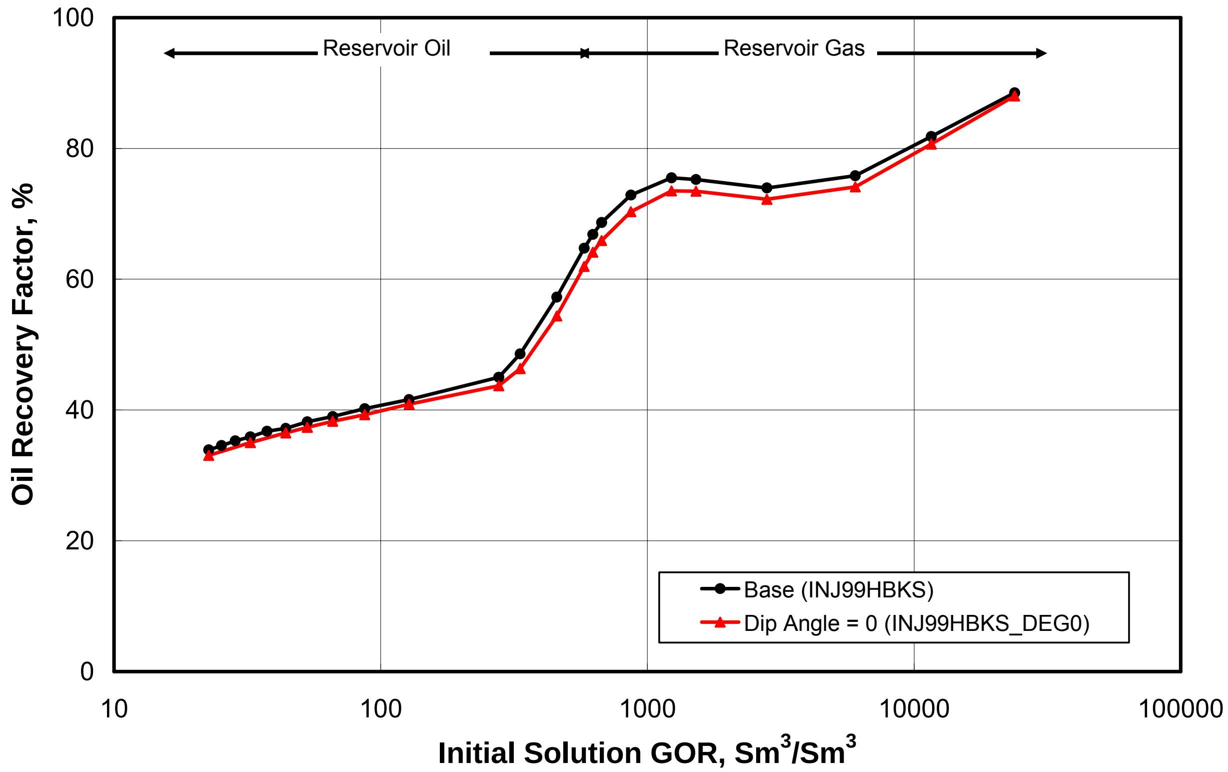

Fig. 19 — Effect of dip angle on the oil recovery – (a) base case: dip angle 3.8 degrees (b) sensitivity cases: dip angle 0 degree).

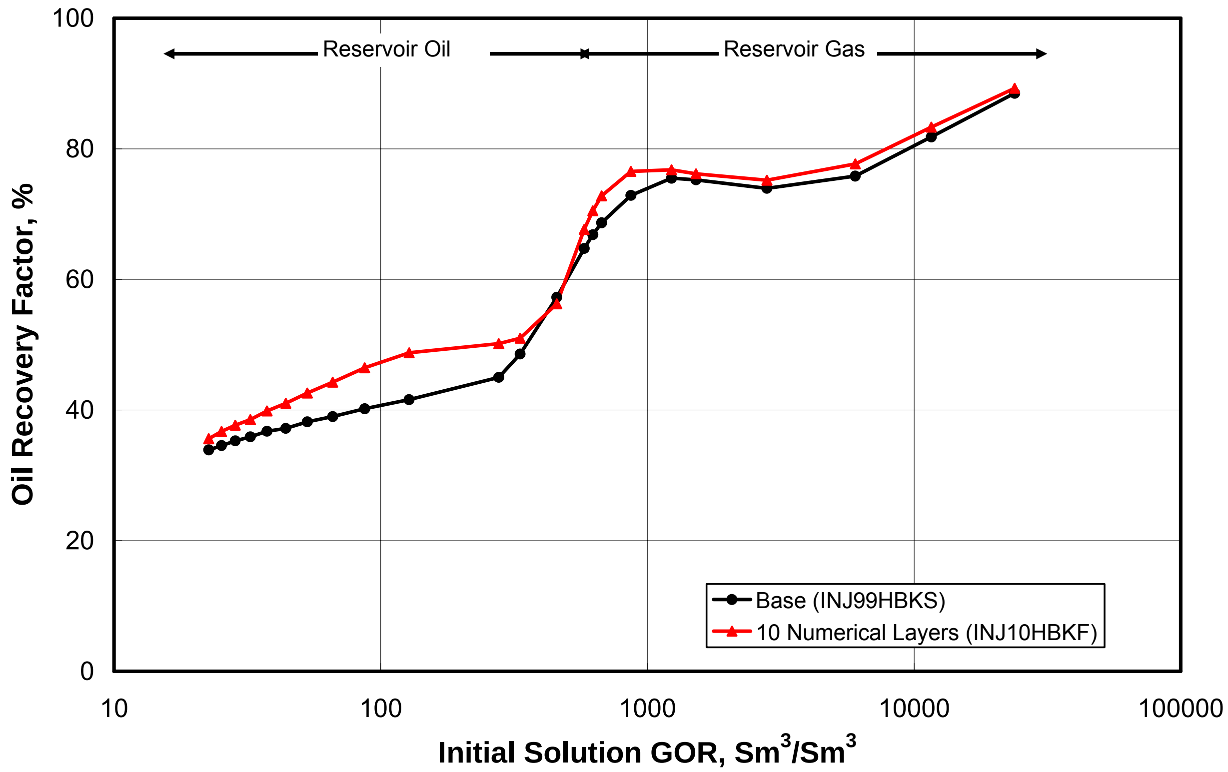

Fig. 20 — Effect of numerical layers on the oil recovery - (a) base case: 99 layers; 15x5x99; each layer with equal thickness (b) sensitivity case: 10 numerical layers; 15x5x10; each layer of equal kh but of different thickness. The total thickness is 150 m in both cases.

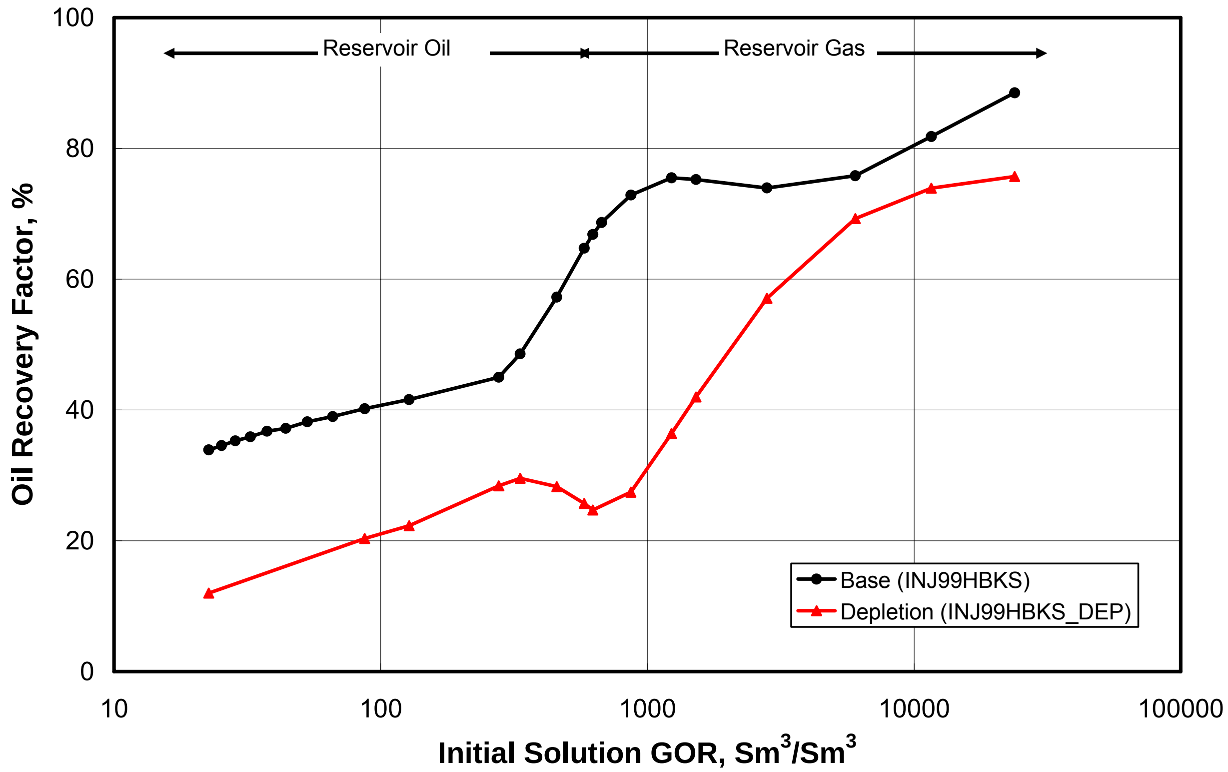

Fig. 21 — Oil recovery under depletion for the case with the highest permeability at bottom – (a) base case: full pressure maintenance at the initial reservoir pressure by lean gas injection (b) sensitivity case: depletion.

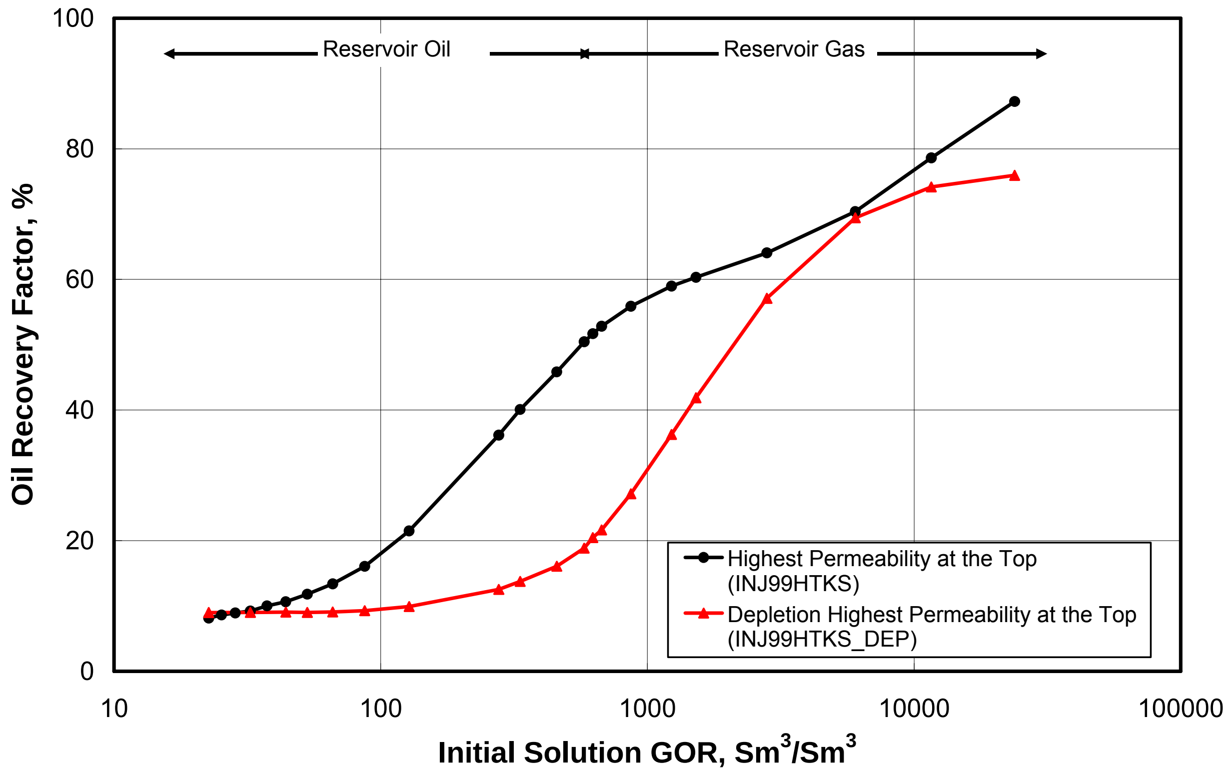

Fig. 22 — Oil recovery under depletion for the case with the highest permeability at the top– (a) full pressure maintenance at the initial reservoir pressure by lean gas injection (b) sensitivity case: depletion.