

**AES/PE/09-22**

**Effect of Reservoir Heterogeneity on  
Immiscible Foam Enhanced Oil Recovery**

**August 2009**

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Title : **Effect of Reservoir Heterogeneity on Immiscible Foam Enhanced Oil Recovery**

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TA Report number : AES/PE/09-22

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# Acknowledgements

I would like to thank specially my supervisor Prof. Dr. P.L.J Zitha for his pleasant and encouraging advice during the whole period of my study at Delft University of Technology Netherlands. I am grateful for the opportunity to be a part of the “foam research group” at TU Delft and for all help and support from fellow students

I would like to express my appreciation for the wonderful attention devoted to me by the co-superior: Mohammad Simjoo (TU Delft) who was there most times to aid me. I am grateful to Dr. Mohand Talanana (Shell) for his contributions and help on the course of my thesis.

Lastly, gratitude goes to Computer Modeling Group Ltd Calgary, Canada for making available to the university simulator STARS, which is a useful tool necessary for integrated reservoir study.

Olatunji Oloruntoba Samuel

August 2009.

# Abstract

Gas flooding is a widely used improved and enhanced oil recovery (IOR/EOR) method. However, due to low density and high mobility of gas compared to oil and water, gas tends to segregate to the top of the reservoir and overrides both oil and water. In heterogeneous and layered reservoirs gas also tends to channel through high permeability streaks. Hence in gas flooding the sweep efficiency is generally poor which leads to low incremental oil recovery factor.

The development of foam leads to lowering the gas mobility and thus can help overcome the above disadvantages and improve the reservoir sweep efficiency.

Many experimental and modeling studies have been devoted to describe foam in the last decade, but questions remain about foam performance in EOR. In particular there are still some important questions regarding foam stability and propagation in reservoirs containing oil and the effect of reservoir heterogeneity. Recent experiments done at the Delft University of Technology have demonstrated that adequately selected surfactants produce foams that are stable in presence of oil. However, if oil saturation is too large there is still a risk that foam will not be sufficiently strong to achieve the desired high recovery factor.

In this study we investigate the effect reservoir heterogeneity on the performance of immiscible foam EOR. The study addresses four different types of reservoir models, homogeneous reservoir, stochastic permeability reservoir, layered reservoir and layered stochastic reservoir. We adopt six different recovery methods starting with water flooding and NFA as a base case, surfactant flooding, gas flooding, foam co-injection, SAG processes and WAG processes.

The simulation results show that foam co-injection has the best sweep efficiency and highest oil recovery. Foam front propagation rate is found to be lower in heterogeneous reservoirs compare with homogenous case and therefore more injection time is needed to reach the same recovery as in the homogeneous case. In all the injection scenarios, the oil recovery in heterogeneous reservoirs is lower.

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# Chapter 1

## Introduction

Primary oil recovery relies on natural reservoir energy such as fluid, rock expansion, solution gas drive, gravity drainage and influx of water from aquifers (Willhite, 1986). Secondary recovery, such as water flooding yields a second batch of oil after primary production has reached its technical and economic limit. One of the problems during water flooding is water override due to density differences between oil and water, therefore the macroscopic displacement efficiency is poor. The initiation and growth of viscous fingers also occur during water flooding as a result of instabilities at the interface between water and oil whenever the viscosity of water is much less than that of the oil. Since reservoirs are inherently heterogeneous, the drive fluid always tends to channel through permeability streaks leaving large fractions of the reservoir unswept. Both effects contribute to poor sweep efficiency during water flooding. In addition, residual oil saturation after water flooding is trapped in several large pores within the reservoir by capillary forces (Fried, 1961). During an imbibition process, as water is being injected into the pore, the oil phase disconnects leaving a trapped or non-flowing glob in the large pore. Reservoir heterogeneity also contributes largely to the trapping of residual oil because of different pore neck radius and internal geometry (Lake, 1989).

Enhanced oil recovery (EOR) refers to methods used to recover more oil from a reservoir than would be produced by primary and secondary recovery (Willhite, 1986). A large body of statistics shows secondary recovery methods leave up to two-thirds of the oil initially in place behind in the reservoir (Green and Willhite, 1998). Different enhanced-oil-recovery (EOR) methods exist to increase the recovery from depleted reservoirs. Gas injection is one of these methods. Theoretically, gas injection could produce almost 100% of the oil because the residual oil saturation tends to be lower to gas than to water (Lake, 1989). However, gas density and viscosity is much lower than oil and water densities therefore gas overrides the oil and leading to early gas breakthrough. The much higher mobility of gas compared to oil and water leads to viscous instability which significantly worsens the override and makes heterogeneity much worse by forming high-mobility channels (Shan and Rossen, 2002). Although the microscopic displacement efficiency is higher for gas flooding,

the volumetric sweep efficiency is rather low due to the above mentioned problems and thereby greatly decreases recovery.

Foam is well known for its ability to reduce gas mobility and effects of heterogeneity and therefore increase sweep efficiency. The use of foam for mobility control was first proposed in 1958 by Bond and Holbrook (1985). Foam greatly reduces the gas mobility since the trapped gas reduces the relative permeability to gas by blocking some of the flow channels (Falls et al, 1989). Furthermore, bubbles that flow experience a significant drag, increasing the effective gas viscosity. Since the use of foam for mobility control was first proposed, several fields trials have been done. Shan reported some foam field trials in which CO<sub>2</sub>, N<sub>2</sub>, air and hydrocarbon gas is injected. Foam applications rely on modeling and simulation studies in addition to detailed laboratory experiments (Nguyen et al, 2000). Many experiments (Mahmoodi and Zitha, 2008) and modeling have been done to investigate the mechanics and behavior of foam in porous media and in absence of oil. Several studies have been devoted to the effect and behavior of foam in heterogeneous porous media.

Renkema and Rossen (2007) did reservoir simulation studies on the design of SAG foam Processes in heterogeneous reservoirs. Cross flow was considered across the heterogeneous reservoirs. They run quite a number of simulations on both homogeneous and heterogeneous reservoirs. They observed that gravity override is better controlled when a fixed-pressure injection process is applied than fixed-rate processes. And also they conclude that a one-cycle SAG outperformed the multiple-cycle SAG in sweep efficiency as well as in duration. Their model did not account for mobile oil, and the effect of oil on foam mobility was disregarded.

Kloet and Rossen (2008) also did simulation studies to confirm the conclusion of Renkema and Rossen. Their study investigates the behaviors of SAG processes applied to heterogeneous and layered reservoirs. They extended their studies to 2D radial, layered reservoirs with four distinct permeability ratios. Optimize the volume of surfactant used in the processes. Also perform some simulations with mobile oil present. Their simulations confirm that fixed-rate processes are outperformed by fixed-pressure processes and also that one-cycle SAG performs better than multiple-cycle SAG. They observed that the reservoirs with small permeability contrast have the best sweep efficiency. However, they further conclude that foam has a remarkable influence in decreasing the effect of permeability contrast. Mobile oil in the reservoirs change the sweeping pattern of the gas.

Zinati et al, (2008) presented a foam modeling and simulation studies on heterogeneous reservoirs based on the stochastic bubble population balance model (Zitha, 2006). They run a number of simulations on layered reservoirs and stochastic permeability reservoir, their models take into account the effect of both cross flow and isolated layer. Their simulation was done in absence of oil. They conclude that in isolated layer reservoir, foam diverts mainly to the high permeable layer and low permeable shows a resistance to foam flow. There is diversion of foam flow from high permeable to low permeable layer in cross flow case, and therefore increase in recovery factor.

The goal of this study is to investigate the influence of reservoir heterogeneity on immiscible foam EOR under realistic field conditions. This study considers four different reservoir models, homogeneous reservoir, stochastic permeability reservoir, layered reservoir and layered stochastic reservoir. Reservoir simulations are done to develop a field with initial oil saturation of 0.85. Six different recovery methods are used water flooding and NFA, surfactant flooding, gas flooding, foam co-injection, SAG processes and WAG processes. Oil viscosity sensitivity analysis was performed. Performance of foam in heterogeneous reservoirs would be compared with that of homogenous reservoir.

# Chapter 2

## Foam theory and background

### 2.1. Foam in porous media.

Foam in porous media is a dispersion of gas in liquid such that the liquid phase is interconnected and at least some of the gas flow paths are blocked by thin liquid films or lamellae (Falls et al, 1986). Capillary pressure and interaction with the reservoir rock are important factors for foam flow in porous media. The curvature of the lamellae curvature is a function of pore dimension and location within the pore space. Diffusion moves lamellae to pore throats where lamellae curvature is zero and diffusion stops. The bubble size and flow are restricted by the pores and when foam flow is considered the consequence of geometry and the connectivity of the porous medium cannot be neglected (Zitha, 2003, Zitha, 2006).

A bulk foam is defined as a foam in a container much larger than individual bubbles. The physical factors controlling bulk foam evolution, patterning and stability are gravity-driven liquid drainage, inter-bubble gas diffusion caused by the pressure difference across the lamellae and lamella thinning and rupture. Foam can be characterized by two main quantities: (a) **Foam quality** is the gas volume fraction of the total injected fluid rate. The quality can vary with both temperature and pressure because the gas volume can vary due to thermal gas expansion and gas compressibility. Besides gas can dissolve in the liquid phase or can come out of solution. Foam qualities can be quite high, approaching 97% in many cases and foam with quality greater than 90% is regarded as dry foam (Lake, 1989).

(b) **Foam Texture** refers to density of foam bubbles. Mobility of foam phase is a strong function of foam texture. This determines how foam will flow through a permeable medium. If the average bubble size is much smaller than the pore diameter, the foam flows as dispersed bubbles in the pore channels. If the average bubble size is larger than the pore diameter, the foam flows as progression of films that separate individual gas bubbles (Lake, 1989).

There are two types of foam relevant to foam injection in reservoir matrix: continuous-gas foam and discontinuous-gas foam. A continuous-gas foam is one in which there exists at least one pathway for gas flow in the pore network that is unblocked by

lamellae. Discontinuous-gas foam is one in which all pathways for gas flow are blocked by lamellae. One cannot distinguish discontinuous and continuous foams directly in opaque rock. The essential difference between the two is the way gas flows through the medium. In continuous gas foam, the gas phase flows as a Newtonian fluid through a medium whose relative permeability to gas has been reduced by lamellae.

## 2.2. Foam generation in porous media

### 2.2.1 Foam generation

Creating individual lamellae is a necessary step in foam generation. The three main mechanisms for foam generation are snap-off, lamella division and leave behind (Ransohoff and Radke, 1988).

Snap-off occurs when gas fingers into a pore constriction and in this pore throat a liquid collar accumulates, due to a capillary pressure and then snaps off (Figure 1).

Lamella division is one means by which flowing foam can reproduce lamellae as they break (Figure 2). Typically, when a bubble reaches a branch point in a flow channel, the bubble may divide into two rather than simply following one of the two available pathways.

Leave behind (Figure 3) occurs when liquid lenses are left behind as two separate bubbles move with the flow direction (Roof, 1970).

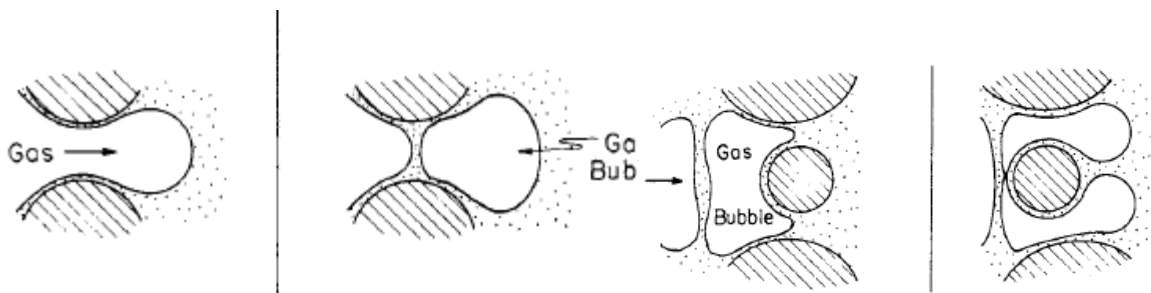


Figure 1 Schematic of Snap-off

Figure 2 Schematic of Lamella division

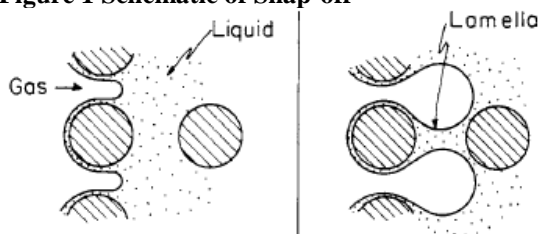


Figure 3 Schematic of Leave- behind

### **2.2.2 Foam destruction**

There are two basic mechanisms of foam coalescence namely gas diffusion and capillary suction. Gas diffusion is a process that primarily pertains to stagnant, trapped bubbles. It is limited in porous media because lamella curvature is not directly and inversely related to bubble volume, but rather to pore dimensions and location within the pore space.

The primary mechanism for lamellae breakage in porous media is capillary suction. The capillary pressure depends on the wetting liquid saturation. Capillary pressure rise leads to decrease film thickness and the disjoining pressure increases above critical capillary pressure, and the film ruptures (Kovscek, and Radke 1994).

### **2.2.3 Foam stability**

Foam lamella forms a two-phase colloidal system where thin intermediate region or boundary lies between the gas and the water refer to as the interface. The attractive van der Waals forces between the water molecules are felt equally by all molecules except those in the interfacial region. This imbalance pulls the molecules of the interfacial region toward the interior of the liquid. The contracting force at the surface is known as the surface tension. Because the surface has a tendency to contract spontaneously in order to minimize the surface area, droplets of water and bubbles of gas tend to adopt a spherical shape. This shape reduces the total free energy at the surface. Work is required to expand the surface against the contracting forces. Each lamella in foam contains two gas-liquid interfaces separated by a thin layer of liquid, and each interface on the lamella has a surface tension. For this reason the film tension is twice the surface tension.

### **2.3. Foam models**

Different methods have been proposed for modeling foam flow in porous media. These models include semi-empirical models (Islam and Farouq, 1990), fractional flow model (Zhou and Rossen, 1995), population balance model (Falls, 1986; Patzek, 1998) and percolation models (Nguyen et al, 2000).

The semi-empirical foam model is a local steady state model in which either the gas relative permeability is decreased or the gas viscosity is increased by a certain factor. This is the mobility reduction factor (mrf), which is a function of surfactant concentration and other factors.

Modeling of foam with the fractional flow theory uses a fixed limiting capillary pressure ( $P_c^*$ ), independent of gas and liquid flow rates and pressure gradient. In that case, gas mobility is only dependent on the fractional flow of water and  $S_w^*$ , which is the water saturation at  $P_c^*$ . This approach is somewhat intermediate between population balance and semi-empirical alteration of gas phase mobility. It relies on the relation between capillary pressure, foam texture and gas mobility.

In the population balance method, the model takes into account all mechanisms of creation and breaking of lamellae. A conservation equation in which the rate of change of foam texture (i.e. lamella or bubble density) depends on the rate of influx, efflux, creation, destruction and trapping of lamellae.

In the percolation, or network, model a disordered medium is represented by a random spatial distribution of connected flow paths of different conductivity. These percolation models need large computational capacity.

## 2.4. Foam modeling in STARS<sup>TM</sup>

There are two general approaches to the modeling of foam flow in STARS<sup>TM</sup>. The first is a Mechanistic or Population- balance model. It allows direct simulation of foam creation, propagation, and coalescence effects such as can be observed in detailed laboratory core experiments. The second approach is semi-empirical model which determines foam mobility reduction through heuristically modified gas mobility curves (Figure 4). The modification is represented by a dimensionless interpolation factor,  $FM$ , which alters the relative-permeability curve for gas in the presence of foam

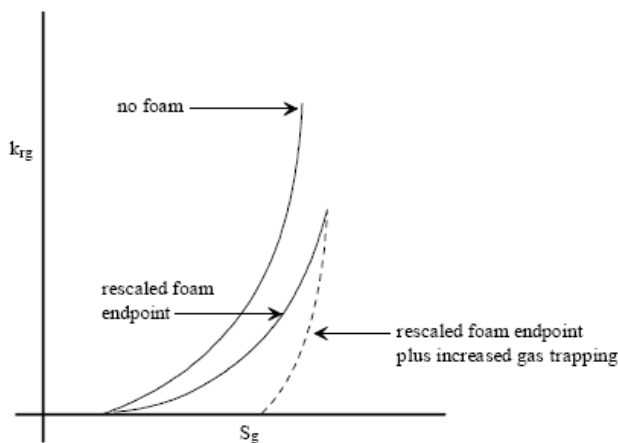


Figure 4 A scaled down gas relative permeability curve due to the presence of foam

For this study, semi-empirical model is used and the assumption is that foam generation occurs instantaneously in the reservoir whenever gas and surfactant coexist. The dimensionless interpolation factor,  $FM$ , depends on six different functions,  $F1-F6$ , and also the parameter  $fmmob$ .  $FM$  is given by

$$K_{rg}^f = K_{rg}^o FM$$

Where

$$FM = \frac{1}{(1 + FMMOB \cdot F1 \cdot F2 \cdot F3 \cdot F4 \cdot F5 \cdot F6)}$$

Where  $FMMOB$  is the reference mobility reduction factor and  $F_i$ , with  $i=1, 2, \dots, 6$  are foam interpolation functions. When at least one of the foam interpolation functions is equal to zero, then  $FM$  is equal to unity. This corresponds to a situation with no foam. In this situation the original gas relative permeability curve is used. Then the foam interpolation functions are all equal to one, foam is at maximum strength and  $FM$  has a value of  $1/(1+FMMOB)$ . In this situation the fully scaled down gas relative permeability curve is used. In all other cases  $FM$  has a value in between and a linear interpolation between the two curves which give the corresponding gas relative permeability curve in this specific situation. The definitions of all the functions are described in detail in appendix A.

In this study the following functions and parameters are considered:  $FMMOB$ ,  $F1$ ,  $F2$  and  $F3$ . The other functions not considered ( $F4$ ,  $F5$  and  $F6$ ) and were set equal to one.

The first interpolation function based on surfactant mole fraction ( $F1$ ) relates a critical surfactant mole fraction ( $fmsurf$ ) and the actual surfactant mole fraction  $Ws$  such way that describe foam strength. For actual surfactant mole fraction  $Ws$  above critical surfactant mole fraction ( $fmsurf$ ), foam is at its maximum strength. For actual surfactant mole fraction  $Ws$  below critical surfactant mole fraction ( $fmsurf$ ), give weaker foam. The relation between foam strength and surfactant mole fraction is governed by  $epsurf$ , where a value of 1 gives a linear dependency.

During surfactant flooding only, it is assumed that the interpolation parameters (DTRAPW a value of wetting phase interpolation parameter for current rock-fluid data set) correspond to the interfacial tension (capillary number) option defined via IFT table. As the surfactant mole fraction increases in the porous media, it lowers the interfacial tension between oil and water.

During foam flooding, surfactant is used not only for lowering the IFT between oil and water but also as foaming agent and to stabilize foam.

The second foam interpolation function ( $F2$ ) describes the influence of oil on foam strength. Above certain oil saturation ( $f_{moil}$ ) the foam will be completely destroyed by oil and there will be no mobility reduction. Below that limit, the foam will be partially destabilized in the presence of oil, and foam mobility will be reduced according to a power law with exponent  $epoil$ . Setting  $epoil$  equal to 1 yields a linear relationship between oil saturation and foam strength for oil saturations less than  $f_{moil}$ .

The third foam interpolation function ( $F3$ ) capillary-number-dependent function. The capillary number is a function of pressure gradient, and the foam gets weaker as pressure gradient increases. The definition of capillary number used in STARS™ is  $(K_{abs} \nabla P / \sigma)$ . In this study the function  $F3$ , using capillary number, has been used to model shear thinning (CMG STARS manual, 2008)

# Chapter 3

## Model description and reservoir heterogeneity

### 3.1 Reservoir models

The reservoir model used in this work consists of  $60 \times 1 \times 30$  grids blocks. Each grid block measures  $40\text{m} \times 1000\text{m} \times 10\text{m}$ , resulting in a rectangular reservoir 2400m long, 1000m wide and 300m tall. The reservoir is 2800m deep and has a slight dip of 8 degrees. The reservoir formation consists of sandstones and three impermeable shale layers within the reservoir. This creates four layers without cross flow and no-flow boundaries are set at all other sides of the reservoir. Four different geological reservoirs model namely, homogeneous, stochastic permeability, layered reservoir and layered stochastic, were created based on permeability variations within the four layers. The representation of each reservoir model is detailed in the next subsection. An injection well and a production well cutting across the four layers are placed at opposite sides of the reservoir and both are perforated over the entire reservoir interval. In all simulations the injection rate is fixed at the injection well and the bottom-hole pressure (BHP) is fixed at the producer.

All simulations start with an initial oil and water saturations of 0.85 and 0.15 respectively. Water-oil and gas-liquid relative permeability table are in appendix B. The gas that is injected is nitrogen and the surfactant concentration in the surfactant solution is 0.5wt%. The capillary number calculations are based on aqueous surfactant IFT. In this model adsorption is taken into account by setting the value of  $fmsurf$  50% higher than CMC value, at CMC adsorption is constant from experimental observations. The fluid properties are the same for all cases. The reservoir oil is light and its viscosity at reservoir conditions is almost four times the viscosity of water. Nitrogen gas molecular mass (0.028 kg/mol) and critical temperature and pressure are  $-146.95\text{ }^{\circ}\text{C}$  and 3394 kPa respectfully while its density, viscosity and compressibility are determined by the simulator. Detailed reservoir and fluid properties and foam parameters are listed in Table 1 and 2 respectively.

Different injection scenarios were carried out to optimize oil recovery, sweep efficiency and microscopic displacement. Then for each injection scenario, water flooding is done for ten years (1.04 PV) until we have 95% water cut and then switch to other injection scenarios as the case may be to allow further recovery.

**Table 1 Reservoir and Fluid parameters**

Parameters	Value	Units
Size of Reservoir	2400×1000×300	[m]
Number of grid blocks	60×1×30	[-]
Absolute permeability	200	[mD]
Porosity	0.22	[-]
Reservoir temperature	71	[°C]
Initial reservoir pressure	165	[bar]
Water density	1023	[kg/m <sup>3</sup> ]
Water viscosity	0.50	[cp]
Water formation volume factor	1.014	
Oil density	853.64	[kg/m <sup>3</sup> ]
Oil Viscosity	1.84	[cP]
Oil formation volume factor	1.09 ~1.24	
S <sub>orw</sub>	0.28	
S <sub>org</sub>	0.10	
S <sub>wc</sub>	0.15	
K <sub>v</sub> /k <sub>h</sub>	0.5	
Water relative permeability Gas relative permeability	In appendix B	
IFT Table	In appendix B	

Data from row 5 to 17 are obtained from TU Delft geosciences course document

**Table 2 Foam parameters**

FMSURF	0.00018
EPSURF	1
FMMOB	1000
FMOIL	0.3
FLOIL	0.1
EPOIL	1
EPCAP	1
FMCAP	2E-04

### 3.1.1 Homogeneous model

The model in figure 5 below represents a homogeneous reservoir. This is modeled to be a reference case. The absolute permeability of sandstones in each layer is 200mD in vertical direction and 400mD in horizontal direction. The impermeable shale layers were set to have zero permeability, thereby creating a no-cross flow in between the layers. Both the sandstones and shale have a porosity of 22%.

### 3.1.2 Stochastic permeability

In order to mimic a realistic geological reservoir, stochastic permeability is modeled in accordance with the shale distribution. The distribution was done in two steps. At first, Permeability was randomly distributed within the range of 50-350mD and then shale lenses

of  $10^{-3}$  mD was randomly introduced. This gives a kind of shaly-sands reservoir as shown in Figure 6. The distribution was generated on excel file using NORMINV function to generate random variables and imported to STARS data file. To have a good comparison with the homogeneous case, stochastic permeability distribution was done to have an average permeability of 200mD. Figure D.1 in appendix D reveals the distribution range.

### 3.1.3 Layered Reservoir

In order to determine the effect of layering in the vertical direction, another heterogeneous reservoir case was modeled having different permeability in each parallel layer. As shown in Figure 7. Upper layer has 2000 mD, second has 200 mD, third has 1000 mD and the last layer has 50mD

### 3.1.4 Layered Stochastic Reservoir

This is another randomly distributed permeability similar to stochastic distribution described above. The four layers are stochastically distributed over different range of permeability. As shown in Figure 8, upper layer ranges between 1400- 2600 mD, second has a range of 100-300 mD, third has a range of 600-1400 mD and the last layer ranges between 20-80mD. The average permeability in each layer correspond with that in (section 3.2.3) layered reservoir described above.

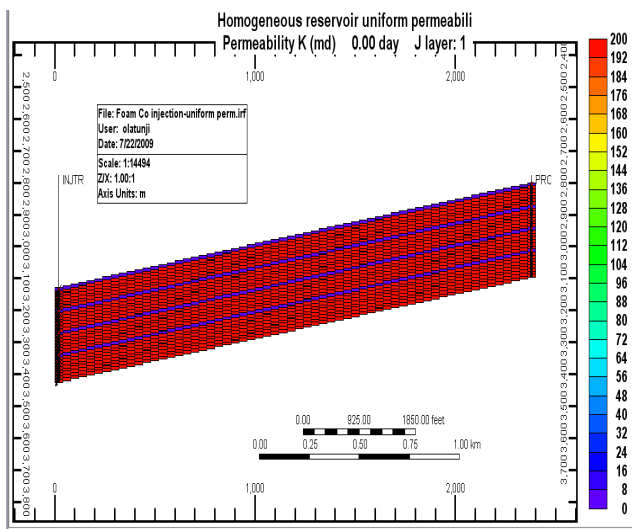


Figure 5: Homogeneous reservoir with 200mD in each layer. The red layers (65m) represent sand bodies. The blue layers (10m) are impermeable shale in between sand bodies.

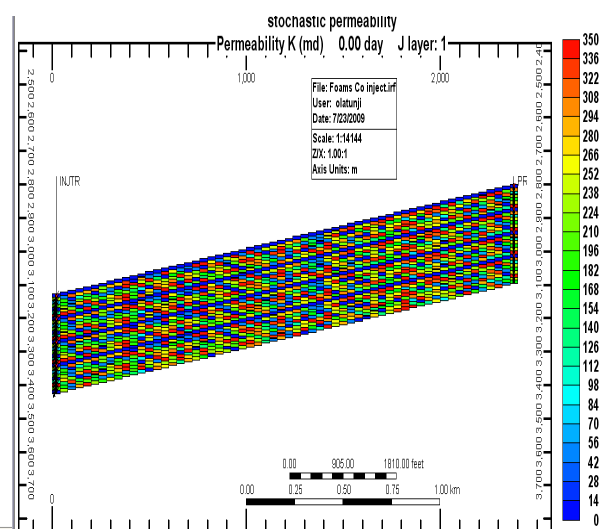


Figure 6: Stochastic permeability reservoir; distributed within 50-350mD in each layer. The multiple color layers (65m) represent sand bodies. The deep blue layers (10m) are impermeable shale in between sand bodies

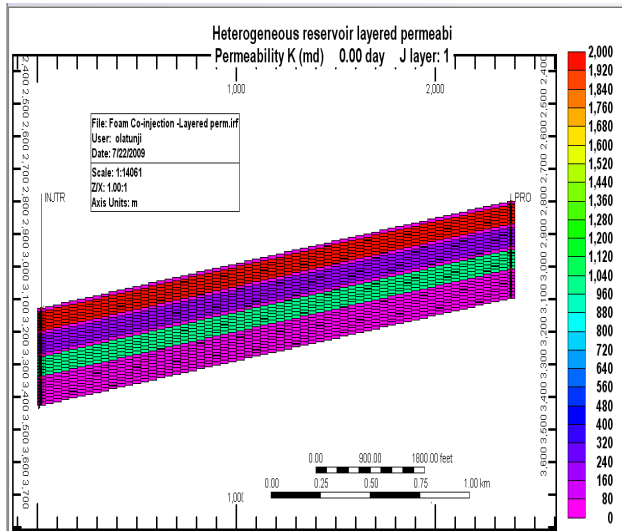


Figure 7. Layered Reservoir-Upper layer has 2000 mD, second has 200mD, third has 1000mD and the last layer has 50mD.

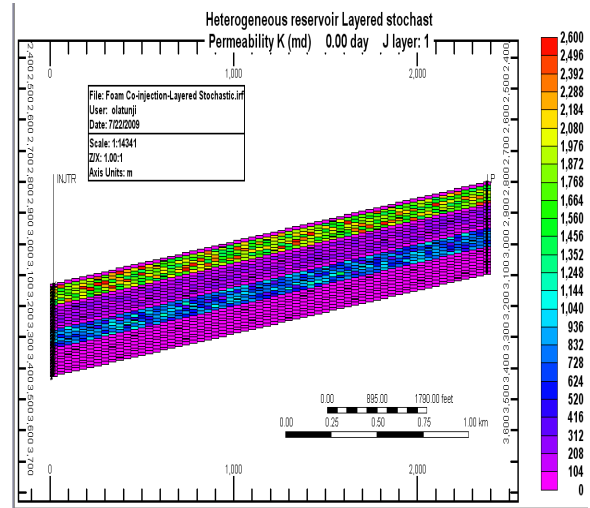


Figure 8. Layered Stochastic Reservoir-Upper layer ranges 1400- 2600mD, second has 100-300 mD, third has 600-1400 mD and the last layer has 20-80mD.

### 3.2 Simulation strategy and scenarios

In this study, different injection scenarios were carried out to optimize oil recovery, sweep efficiency and microscopic displacement. All the injection scenarios start with water flooding for 10 years equivalent to 1.04 PV and there after change to another means of recovery for 40 years. The injection scenarios carried out are as follows

*Scenario 1:* Base Case: Water flooding and No Further Action

*Scenario 2:* Surfactant Flooding following Water Flooding.

*Scenario 3:* Gas Flooding following Water Flooding.

*Scenario 4:* Foam co-injection following Surfactant pre-flush and Water Flooding.

*Scenario 5:* SAG processes following Water Flooding

*Scenario 6:* WAG processes following Water Flooding

All other reservoir and fluid properties remains the same as listed in Table 1

# Chapter 4

## Simulation results and discussion

### 4.1 Discussion of results

#### 4.1.1 Base Case: Water flooding & No further action

A base case simulation is first run on the four different reservoir models at the same injection rate and the same bottom-hole pressure at the producer. Water is injected for 10 years (1.04 PV) and there after continued with No Further Action for 40 years (4.46 PV).

Figure 9-12 show oil saturation maps after water injection for 50 years in the four different reservoir models. Homogeneous reservoir appears to have the best sweep efficiency compare with other heterogeneous cases. It can be seen clearly that most of the shaly-sand spots in stochastic permeability are left almost unswept. While in both Layered reservoir and Layered Stochastic, the last layer is partly swept due to low permeability. It is observed that when there is water break through in any of the layers, the water relative permeability in that layer increases and water continue channeling through it therefore leads to poor sweep efficiency

Figure 14 shows plot of water cut versus time from which the break through time for each reservoir model can be inferred. In the homogeneous reservoir, water break through in the four layers at about the same time, after 1954 days (5.35 yrs) for 0.56 PV of water injection. It is obvious from the plot that there is a slight delay in breakthrough time for stochastic reservoir, this could be that heterogeneity slightly mitigates the effect of gravity override. The water breakthrough in all the layers is after 2107 days (5.77 yrs) for 0.60PV of water injection. Layered reservoir and layered stochastic reservoir both have the same trend of three breakthrough time. The upper layers have the shortest breakthrough time of 747 days (0.213PV) and 744 days (0.214PV) respectively because of high permeability and the third layer have the second break through time of 1397 days (0.39PV) & 1510 days (0.43PV) respectively and the third break through is after 6172 days (1.76PV) and 5705days (1.63PV) respectively. The last layer never experienced breakthrough.

Cumulative oil production and the recovery factors corresponding to Figure 15, Figure 16 and Table 3 respectively. Not surprisingly, the results show that homogeneous reservoir has the highest oil recovery (56.5%) and much better sweep efficiency than the other three heterogeneous scenarios. In stochastic permeability reservoir, the recovery factor reduced drastically (42.1%) because of wide permeability contrast and more oil is trapped due to capillary force and rock fluid interactions operating on the multiple scales which leads to poor

microscopic displacement. Both the layered reservoir and layered stochastic reservoir have recovery factors of 53.9% and 51.7% respectively higher than that stochastic distribution. Both reservoirs have a high permeability channels in the first and third layer, which result in early breakthrough in those two layers. Therefore sweep efficiency is poor and hardly increases once displacing fluid has broken through in one of the layers.

The pressure gradients for each reservoir model are presented in Figure 17-20 homogeneous reservoir has a uniform pressure gradient (0.23psi/ft) in each layer. Stochastic permeability reservoir also has a relatively uniform pressure gradient in each layer as well, but the pressure gradient doubled to 0.46psi/ft because high resistance to flow within low permeability grids. Layered reservoir and layered stochastic reservoir have slight variation in pressure gradient. The three upper layers have a pressure gradient of 0.14psi/ft and 0.16psi/ft in the last layer for layered reservoir, while the layer stochastic has a pressure gradient of 0.15psi/ft in the three upper layers and 0.18psi/ft in the last layer.

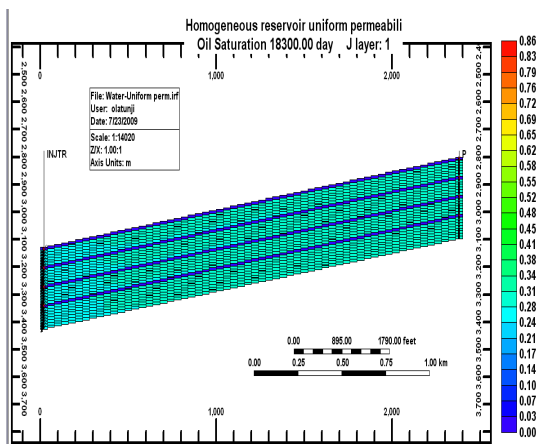


Figure 9: Homogeneous Reservoir: Oil saturation map after 50 years of water flooding

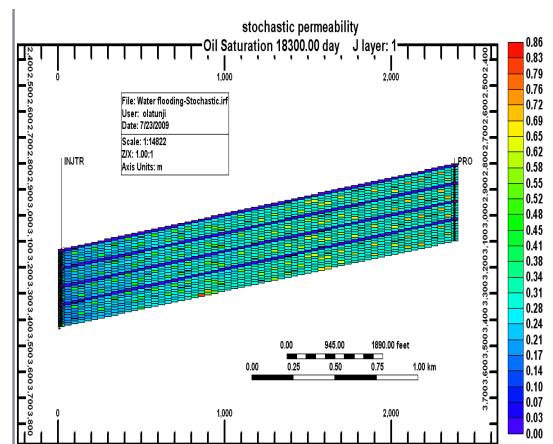


Figure 10: Stochastic permeability: Oil Saturation map after 50 years of water flooding

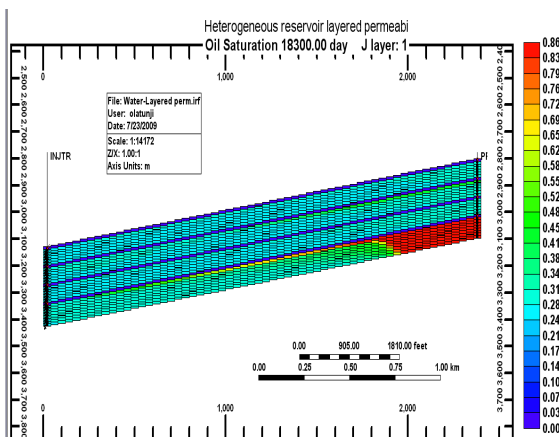


Figure 11: Layered Reservoir: Oil Saturation map after 50 years of water flooding

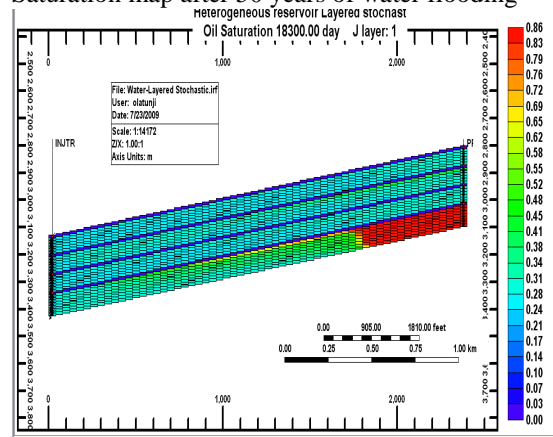


Figure 12: Layered Stochastic Reservoir: Oil Saturation map after 50 years of water flooding

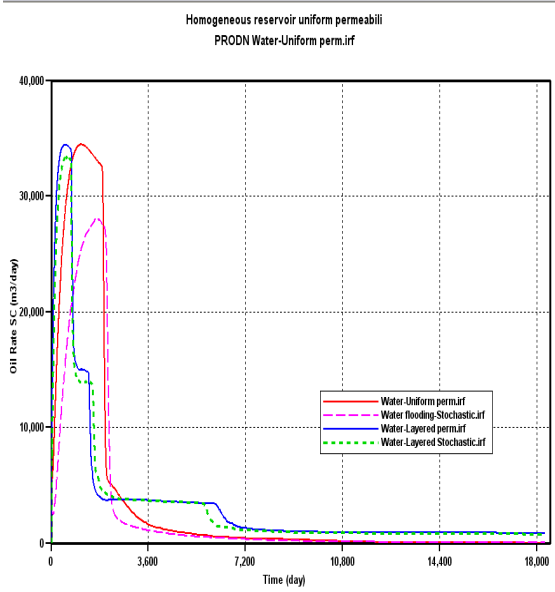


Figure 13: Oil production rate for water flooding & NFA (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered-reservoir and (green line) is layered stochastic reservoir

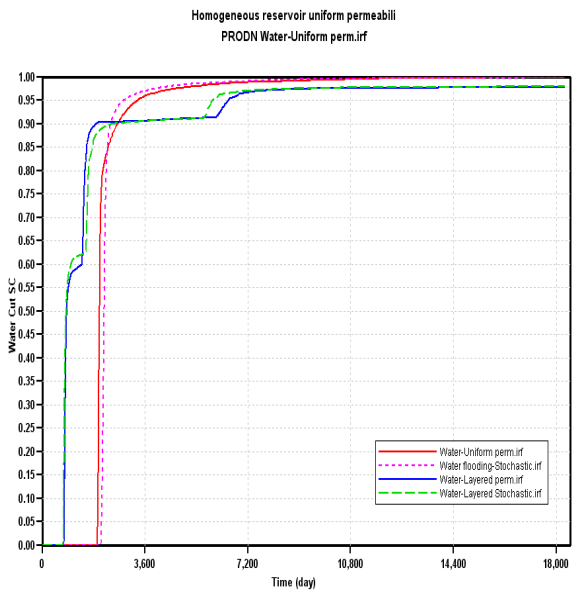


Figure 14: Water cut for water flooding & NFA, (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered reservoir and (green line) is layered stochastic reservoir

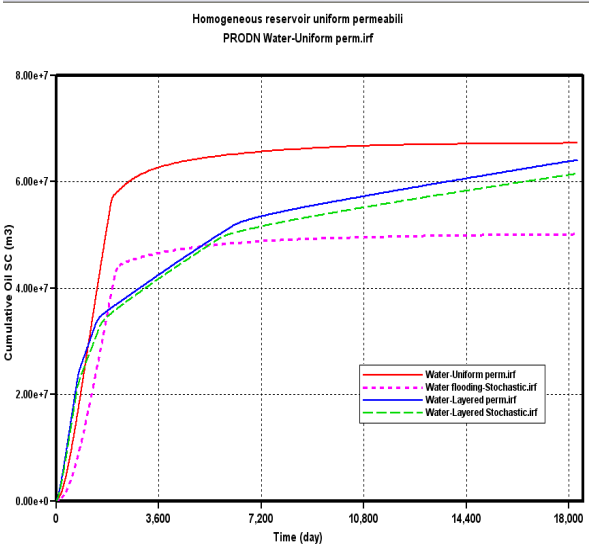


Figure 15: Cumulative oil production for water flooding & NFA (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered-reservoir and (green line) is layered stochastic reservoir

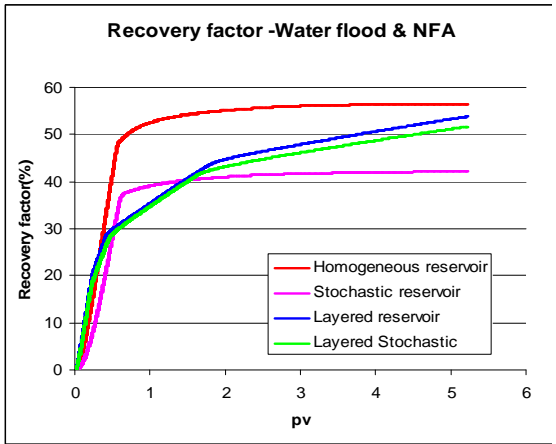


Figure 16: Recovery factors- Water flooding & NFA

**Table 3: Recovery factors with respect to water flooding for 10 years & NFA for 40 years**

Different models	Reservoir	RF – Water flooding 10 years	RF-Additional Flooding 40 years	Water	Total RF after 50 years
Homogenous Reservoir 200mD		52.7%	3.8%		56.5%
Stochastic Distribution 50- 350mD		39.1%	3.0%		42.1%
Layered Reservoir 2000mD 200mD 1000mD 50mD		35.7%	18.2%		53.9%
Layered stochastic Distribution 1400-2600mD 100-300mD 600-1400mD 20-80mD	stochastic	35.1%	16.6%		51.7%

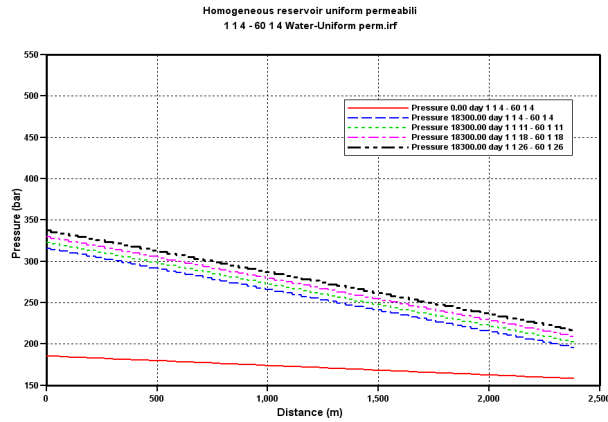


Figure 17: Pressure profile after 50 years- Homogeneous reservoir, pressure gradient=0.23psi/ft

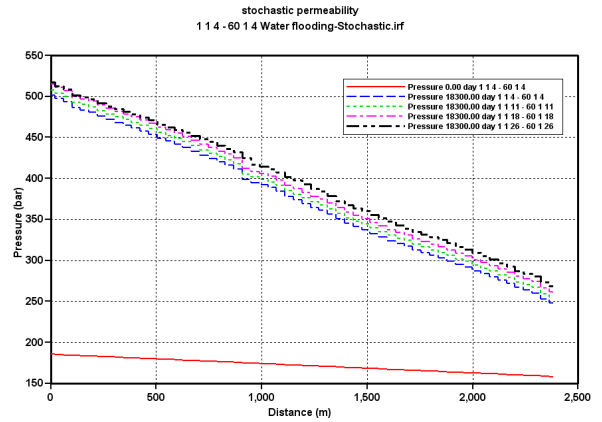


Figure 18: Pressure profile after 50 years - Stochastic permeability reservoir, pressure gradient=0.46psi/ft

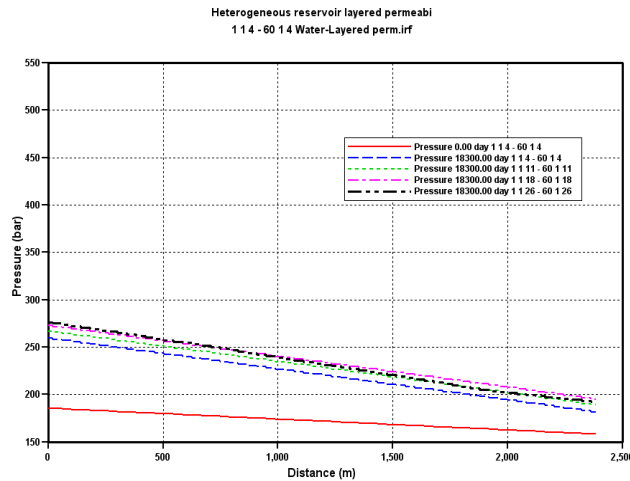


Figure 19: Pressure profile after 50 years- Layered reservoir, pressure gradient of 0.14psi/ft in the three upper layers and 0.16psi/ft in the last layer

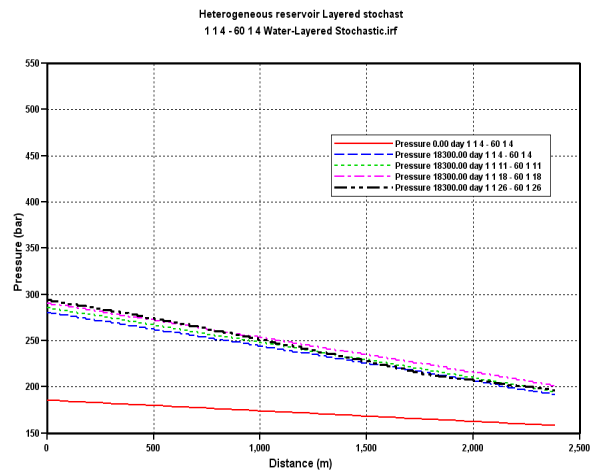


Figure 20: Pressure profile after 50 years- Layered stochastic reservoir, pressure gradient of 0.15psi/ft in the three upper layers and 0.18psi/ft in the last layer

### 4.1.2. Surfactant flooding following Water Flooding

Using the same approach as described in the base case simulation (section 4.1), to estimate the impact of surfactant flooding as a means of EOR. Simulations run on the four different reservoir models at the same injection rate and the same producer bottom-hole pressure. Water is injected for 10 years (1.04 PV) and there after switch to surfactant flooding for 40 years (4.46 PV).

Figure 21-24 show oil saturation maps after 10 years water injection followed by 40 years surfactant flooding for the four different reservoir models. Physically, the figures look similar and have the same trend with those obtained in base case. However, the plots of surfactant mole fraction versus distance in Figure 25-28 show the saturation of surfactant within each reservoir model. In homogeneous reservoir, surfactant solution penetrates completely through all the four layers. Figure 25 revealed the average surfactant mole fraction within the reservoir is 0.000254 which is lower than injected solution mole fraction (0.00028) due to rock adsorption. Stochastic reservoir also has surfactant mole fraction entirely across the four layers, but the mole fraction varies. The jumps on the plot corresponds to low permeability spot (shaly-sand) and the average surfactant mole fraction on these spots is  $3.12 \times 10^{-7}$ , while the remaining part have an average surfactant mole fraction of 0.000251.

In both Layered reservoir and Layered Stochastic reservoir the last layer is also experienced partly swept due to low permeability (50mD). And the plots of surfactant saturation also indicate that more than half of the last layers were not touched by surfactant solution.

Figure 30 indicates the water-cut for each reservoir model. However, the breakthrough time is the same with the base case result (section 4.1), because breakthrough occurred in all the reservoir models before the elapse of 10 years water flooding.

Figure 31 and 32 show that homogeneous reservoir has the highest oil recovery (56.6%) and much better sweep efficiency than the other three heterogeneous scenarios, and stochastic permeability reservoir, with the least recovery factor (48.7%).

Both the layered reservoir and layered stochastic, have recovery factors of 54.2% and 52.0% respectively. This is higher than that stochastic permeability because of higher permeability channels in first and third layer. However, water breakthrough as indicated in Figure 30, occurred earlier in those two layers than for the homogeneous case. This makes recovery

lower than homogeneous case, again the sweep efficiency is poor and hardly increases once displacing fluid has broken through in one of the layers.

Table 4 shows the difference between 40 years surfactant flooding and 40 years NFA in base case. Stochastic permeability has better microscopic displacement efficiency with surfactant flooding than the others, because more oil are trapped in the reservoir after 10 years water flooding than in homogeneous case, Figure C.5-C.8 in Appendix C reveals. The surfactant lowers the IFT between oil and water and allows easier spreading. During surfactant flooding, STARS<sup>TM</sup> takes into account the interpolation parameters (DTRAPW which is a value of wetting phase interpolation parameter for current rock-fluid data set) correspond to the interfacial tension (capillary number) option defined via IFT table. The plot obtained from IFT table shows that as the surfactant mole fraction increases in the porous media, the interfacial tension between oil and water decreases.

Similar to the base case, plots of the pressure gradient for each reservoir model are presented in Figure 33-36. The homogeneous reservoir has a uniform pressure gradient (0.23psi/ft) in each layer. Stochastic permeability reservoir also has a relatively uniform pressure gradient in each layer as well. It is observed that there is a sharp drop in pressure gradient to 0.28psi/ft when compare with the base case. This can be explained as resulting of lower IFT which lowers capillary pressures jumps between blocks. Layered reservoir and layered stochastic reservoir have slight variation in pressure gradient. The three upper layers have a pressure gradient of 0.14psi/ft and 0.16psi/ft in the last layer for layered reservoir, while the layer stochastic has a pressure gradient of 0.17psi/ft in the three upper layers and 0.18psi/ft in the last layer.

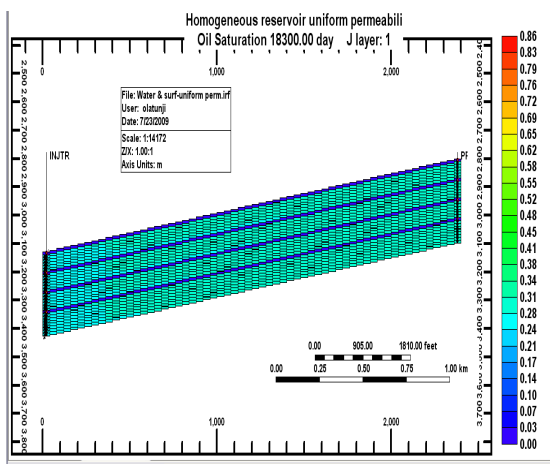


Figure 21: Homogeneous reservoir, Oil saturation map after 10 years of water flooding and 40 years of surfactant flooding

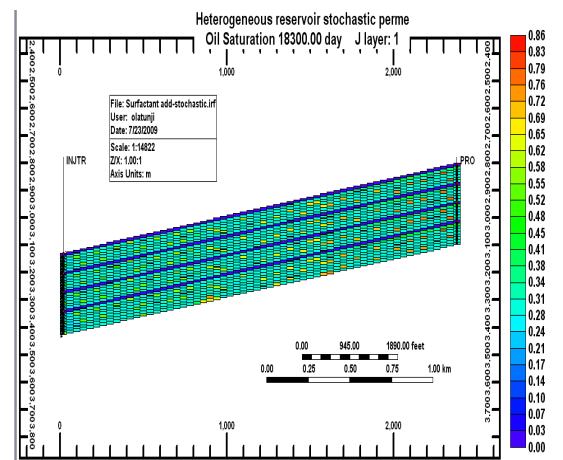


Figure 22: Stochastic permeability reservoir, Oil saturation map after 10 years water flooding and 40 years surfactant flooding

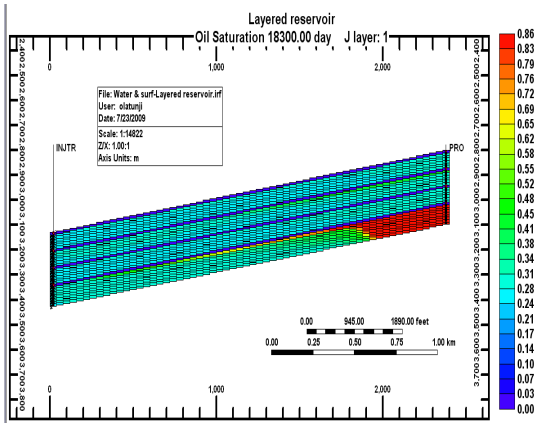


Figure 23: Layered reservoir, Oil saturation map after 10 years water flooding and 40 years of surfactant flooding

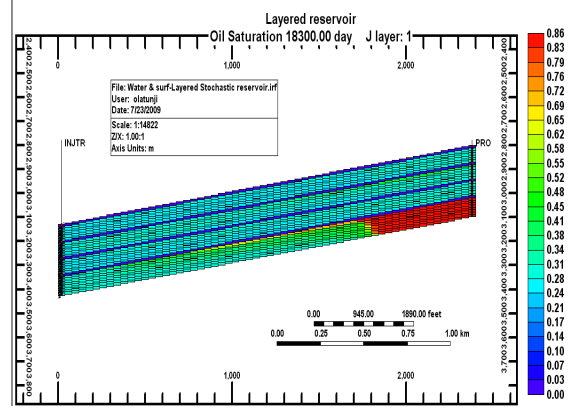


Figure 24: Layered stochastic reservoir, Oil saturation map after 10 years water flooding and 40 years surfactant flooding

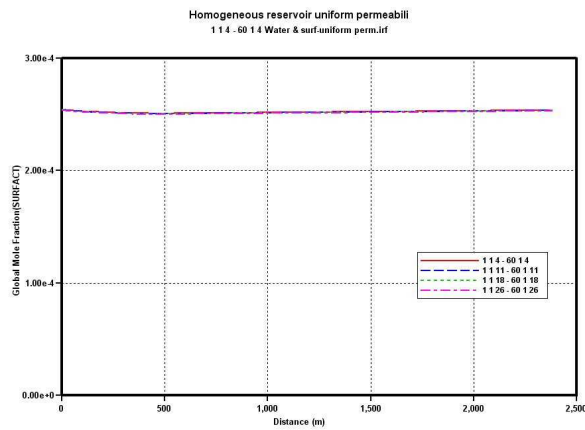


Figure 25: Homogeneous reservoir, surfactant saturation profile mole fraction after 10 years water flooding & 40 years of surfactant flooding. (red line) is upper layer,(blue line) is second layer,(green line) is third layer and (purple line) is last Layer

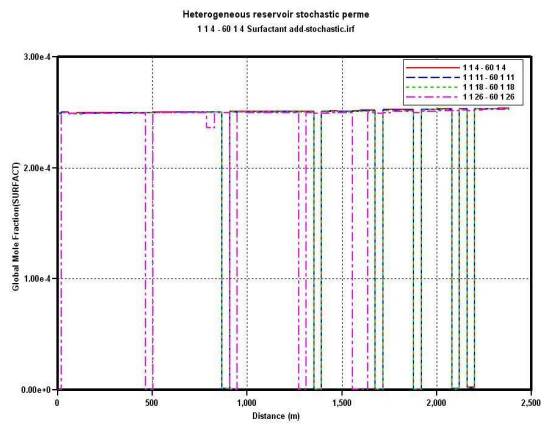


Figure 26: Stochastic permeability, surfactant saturation profile mole fraction after 10 years water flooding & 40 years of surfactant flooding. (red line) is upper layer,(blue line) is second layer,(green line) is third layer and (purple line) is last Layer

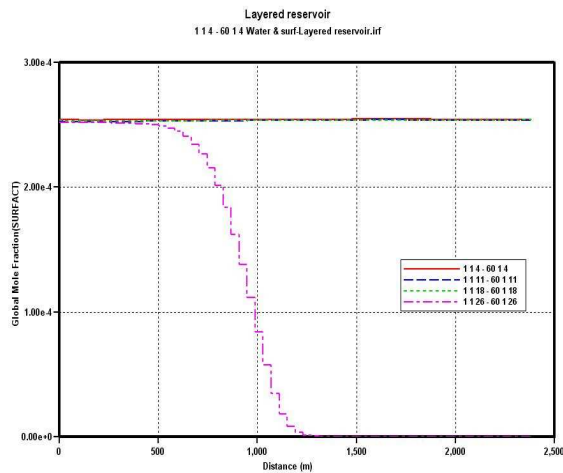


Figure 27: Layered reservoir, surfactant saturation profile mole fraction after 10 years water flooding & 40 years of surfactant flooding. (red line) is upper layer, (blue line) is second layer, (green line) is third layer and (purple line) is last Layer

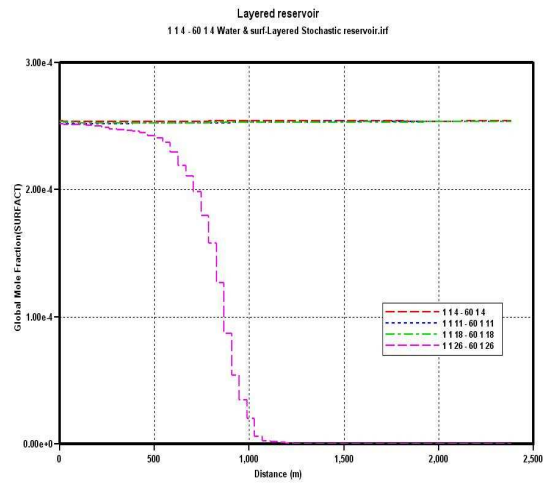


Figure 28: Layered stochastic, surfactant saturation profile mole fraction after 10 years water flooding & 40 years of surfactant flooding. (red line) is upper layer, (blue line) is second layer, (green line) is third layer and (purple line) is last Layer

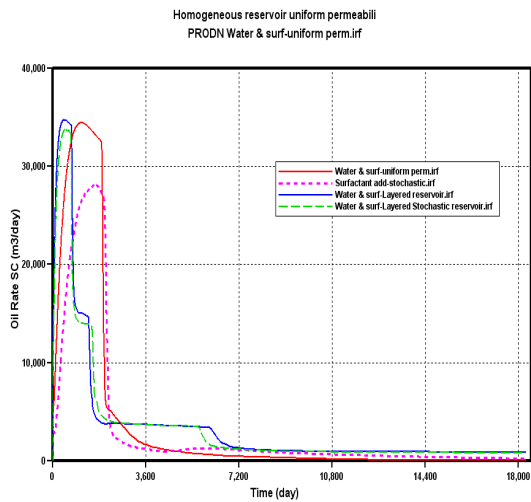


Figure 29: Oil production rate -water flooding follow by surfactant flooding (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered reservoir and (green line) is layered stochastic reservoir

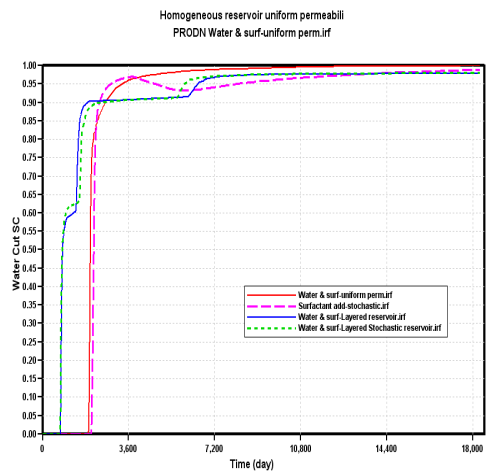


Figure 30: Water cut -water flooding follow by surfactant flooding (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered reservoir and (green line) is layered stochastic reservoir

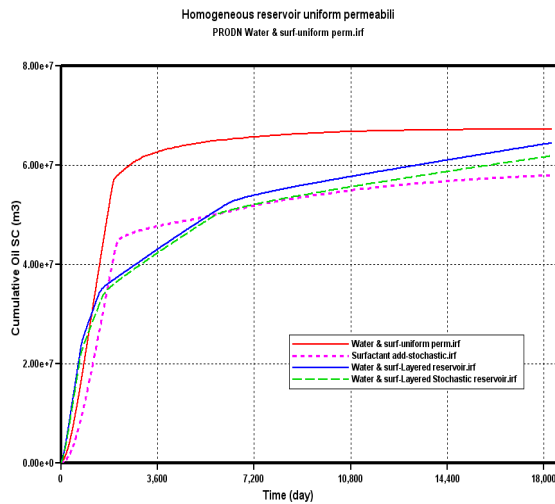


Figure 31: Cumulative oil production for water flooding follow by surfactant flooding. (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered-reservoir and (green line) is layered stochastic reservoir

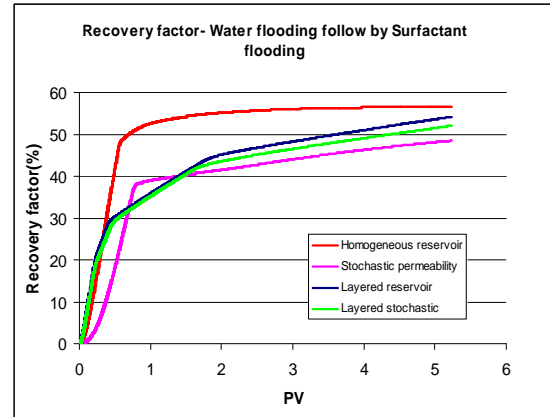


Figure 32: Recovery factor -Water flooding follow by surfactant flooding.

**Table 4: Recovery factors -Water flooding for 10 years follow by surfactant flooding for 40 years**

Different Scenarios	RF – Water flooding 10 years	RF-Surfactant Flooding 40 years	Total RF after 50 years	Difference between 40 yrs surfactant flooding and 40 yrs NFA
Homogenous Reservoir 200mD	52.7%	3.9%	56.6%	0.1%
Stochastic Distribution 50- 350mD	39.1%	9.8%	48.9%	6.8%
Layered Reservoir 2000mD 200mD 1000mD 50mD	35.7%	18.5%	54.2%	0.3%
Layered stochastic Distribution 1400-2600mD 100-300mD 600-1400mD 20-80mD	35.1%	16.9%	52.0%	0.3%

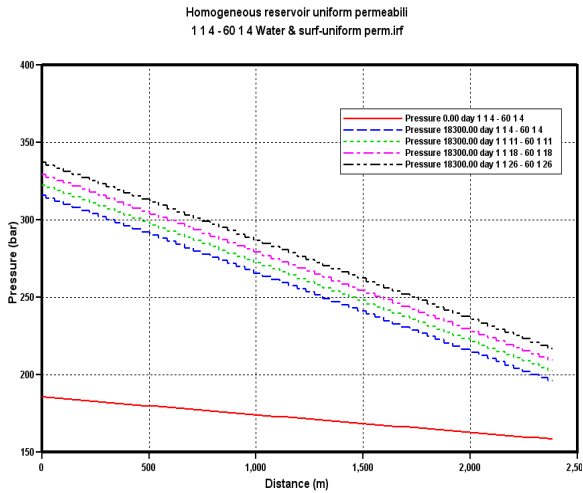


Figure 33: Pressure profile after 50 years - Homogeneous reservoir pressure gradient=0.23psi/ft

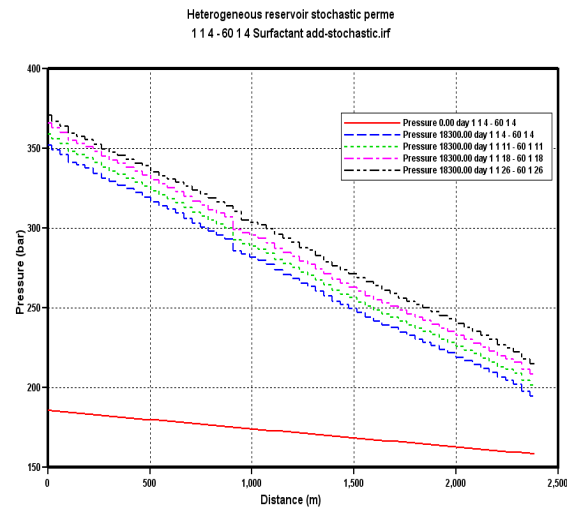


Figure 34: Pressure profile after 50 years -stochastic reservoir pressure gradient=0.28psi/ft

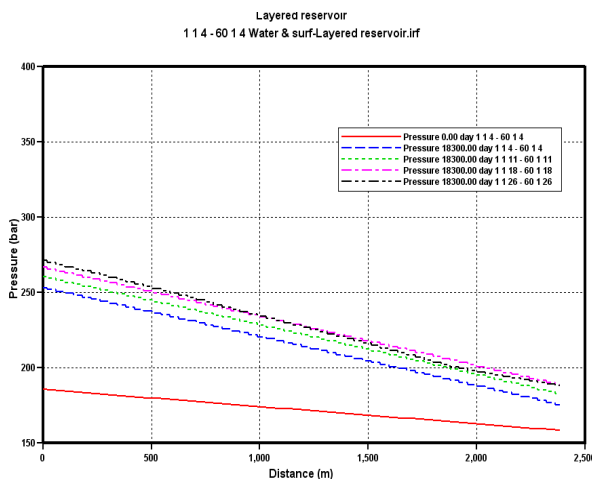


Figure 35: Pressure profile after 50 years – Layered reservoir, pressure gradient of 0.14psi/ft in the three upper layers and 0.16psi/ft in the last layer

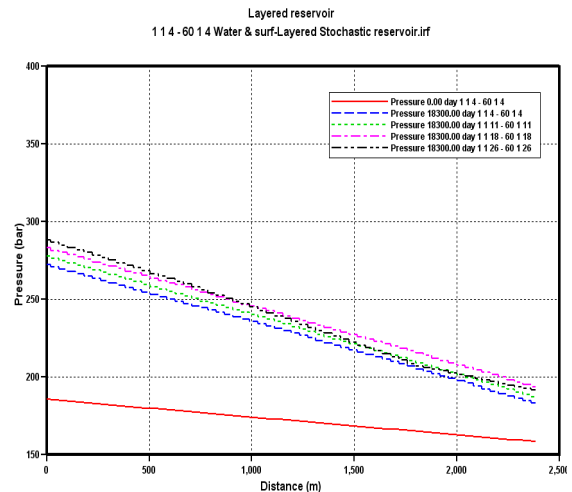


Figure 36: Pressure profile after 50 years- Layered stochastic reservoir. pressure gradient of 0.17psi/ft in the three upper layers and 0.18psi/ft in the last layer

### 4.1.3. Gas injection following water flooding

Running the third simulation on the four different reservoir models at the same injection rate and the same producer bottom-hole pressure. Water is injected for 10 years (1.04 PV) and there after switch to gas injection for 40 years.

Figure 37-40 show oil saturation maps and Figure 41-44 show the gas saturation maps after 10 years water flooding and 40 years gas injection in the four different reservoir models. It is observed that there is gas override in all the reservoir models, consequently this leads to significantly poorer sweep efficiency. It is expected that gas injection could have done a better recovery because the residual oil saturation to gas (0.10) is set lower than the residual oil saturation to water (0.28). Due to low gas density and high gas mobility, gas overrides the

oil leading to early gas breakthrough. However, the extent of override in each reservoir model varies. In homogeneous reservoir the injected gas moved through the upper part of each layer to the production well. While in the stochastic reservoir, injected gas bypassed the oil by flowing through higher permeable streaks.

A severe gas override is observed in both layered reservoir and layered stochastic. The injected gas is channeling through the first layers only and this makes sweep efficiency worse

Figure 47 and 48 show that homogeneous reservoir has the highest oil recovery (57.6%) while both layered reservoir and layered stochastic reservoir, with the least recovery factor (41.6%) each.

Table 5 indicates the difference between 40 years gas injection and 40 years NFA. Stochastic permeability appears to have the highest recovery (9.2%) by gas flooding. The negative values of -12.3% and -10.1% for layered reservoir and layered stochastic respectively, indicate that NFA did a better recovery than gas injection.

Figure 49-52 show the pressure profile at the end of 50 years. The pressure gradients are 0.05psi/ft, 0.04psi/ft, 0.06psi/ft and 0.06psi/ft for homogeneous, stochastic, layered reservoir and layered stochastic respectively. There are pressure pulses in stochastic permeability because of low permeable spot. The pressure gradients all appeared to be generally low compare with base case and surfactant flooding. This is as a result of severe gas override and early gas breakthrough.

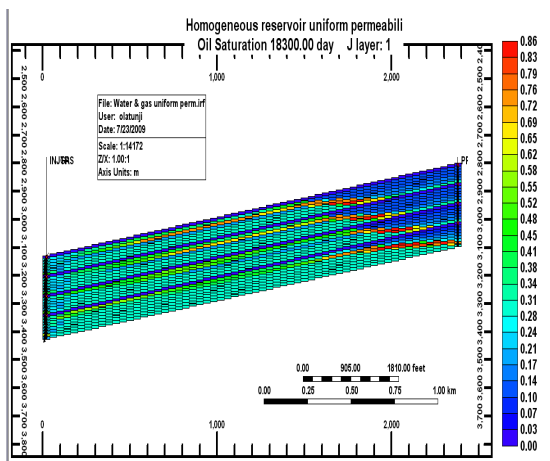


Figure 37: Homogeneous reservoir-Oil saturation map after 10 years water flooding & 40 years gas injection.

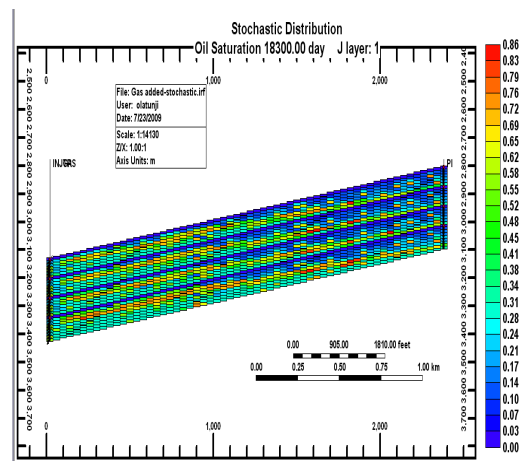


Figure 38: Stochastic permeability reservoir-Oil saturation map after 10 years water flooding & 40 years gas injection.

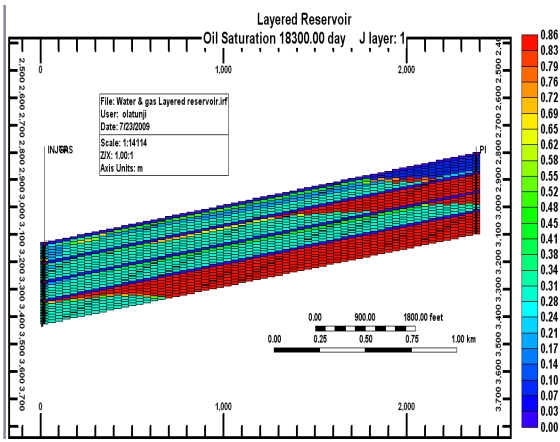


Figure 39: Layered Reservoir- Oil saturation map after 10 years water flooding & 40 years gas injection

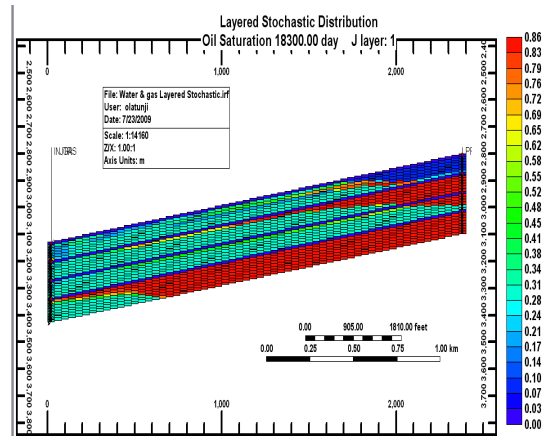


Figure 40: Layered stochastic reservoir- Oil saturation map after 10 years water flooding & 40 years gas injection

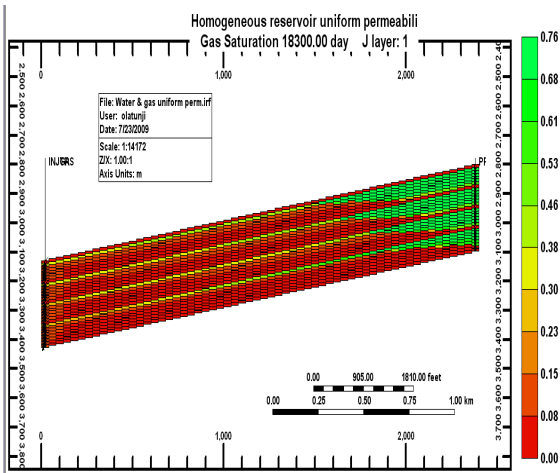


Figure 41: Homogeneous reservoir- Gas saturation map after 10 years water flooding follow by 40 years gas injection

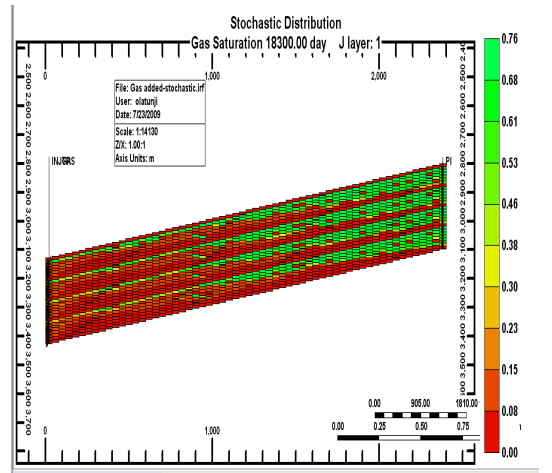


Figure 42: Stochastic permeability reservoir- Gas saturation map after 10 years water flooding follow by 40 years gas flooding

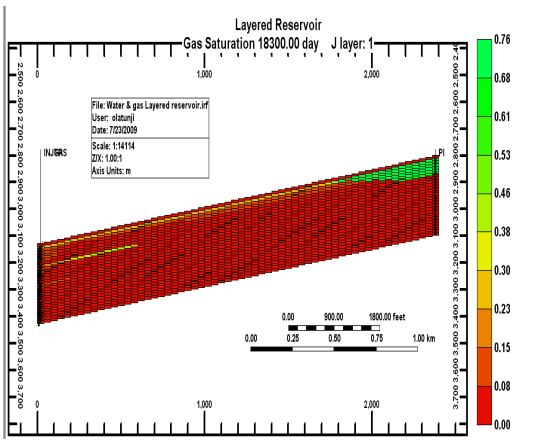


Figure 43: Layered reservoir- Gas saturation map after 10 years water flooding & 40 years gas injection

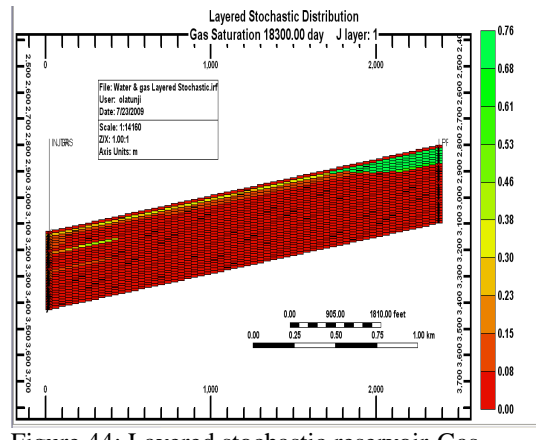


Figure 44: Layered stochastic reservoir- Gas saturation map after 10 years water flooding & 40 years gas injection

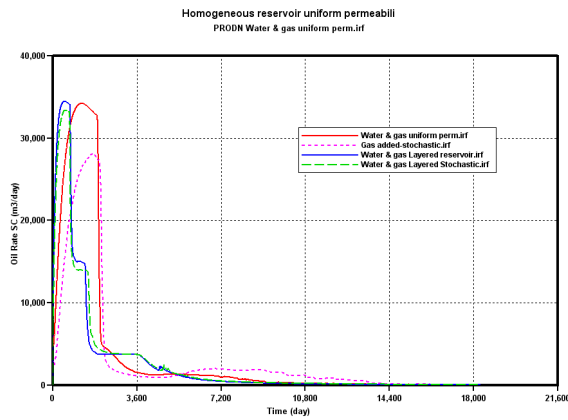


Figure 45: Oil production rate-Water flooding and gas injection (red line) is homogeneous reservoir,(purple line) is stochastic permeability reservoir,(blue line) is layered reservoir and (green line) is layered stochastic reservoir

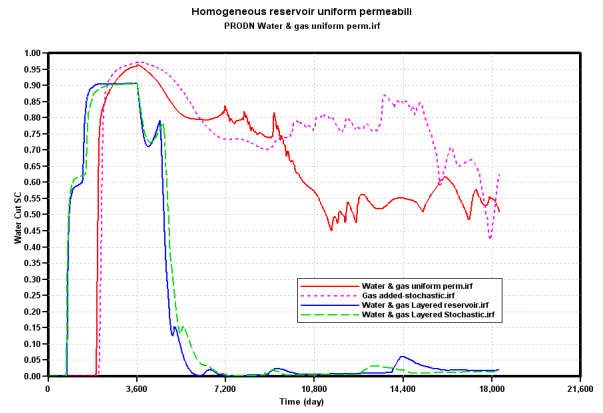


Figure 46: Water cut-Water flooding follow by gas injection (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered reservoir and (green line) is layered stochastic reservoir

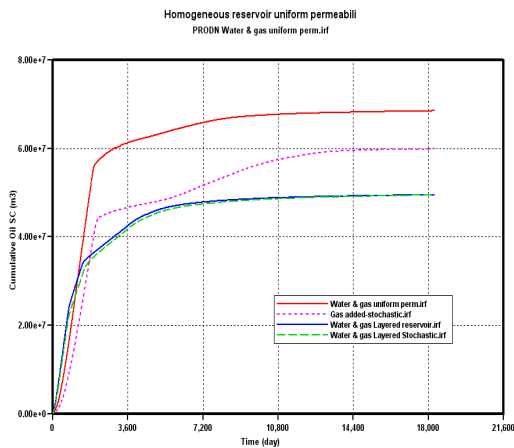


Figure 47: Cumulative oil production- 10 years water flooding & 40 years gas injection (red line) is homogeneous reservoir,(purple line) is stochastic permeability reservoir,(blue line) is layered reservoir and (green line) is layered stochastic reservoir

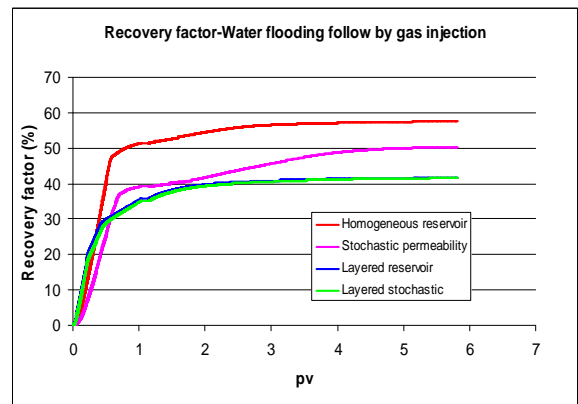


Figure 48: Recovery factors-Water flooding follow by gas injection

**Table 5: Recovery factor-10 years water flooding &40 years Gas injection**

Different Scenarios	RF – Water flooding 10 years	RF-Gas Injection 40 years	Total RF after 50 years	Difference between 40 yrs gas injection and 40yrs NFA	Remarks
Homogenous Reservoir 200mD	52.7%	4.9%	57.6%	1.1%	
Stochastic Distribution 50- 350mD	39.1%	11.2%	50.3%	9.2%	
Layered Reservoir 2000mD 200mD 1000mD 50mD	35.7%	5.9%	41.6%	-12.3%	Negative indicates that NFA recovery is higher than gas recovery
Layered stochastic Distribution 1400-2600mD 100-300mD 600-1400mD 20-80mD	35.1%	6.5%	41.6%	-10.1%	Negative indicates that NFA recovery is higher than gas recovery

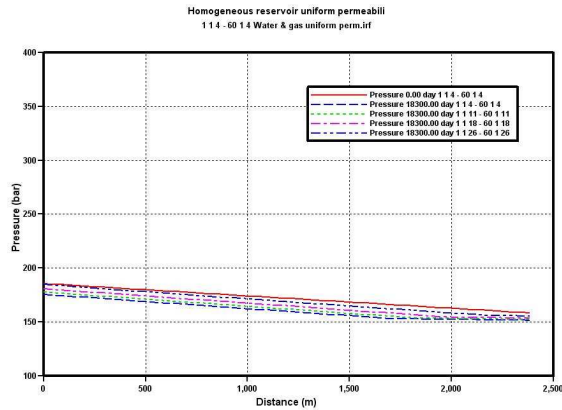


Figure 49: Pressure profile –Homogeneous reservoir. Pressure gradient =0.05psi/ft

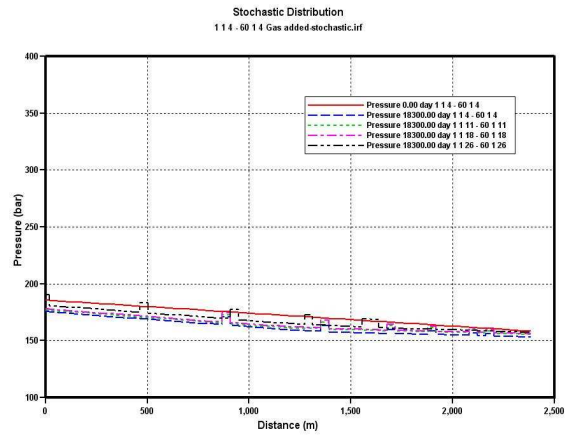


Figure 50: Pressure profile –Stochastic permeability. Pressure gradient=0.04psi/ft

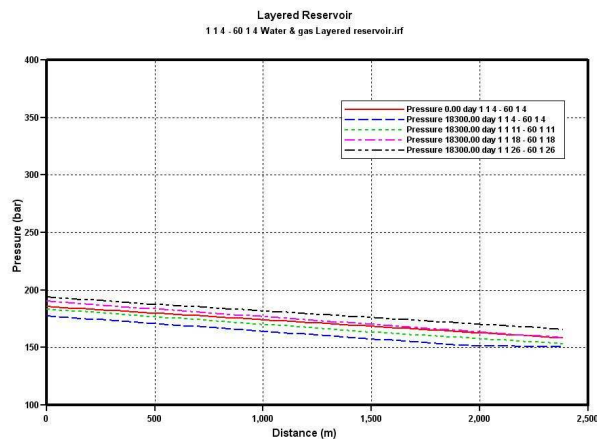


Figure 51: Pressure profile- Layered reservoir. Pressure gradient=0.06psi/ft

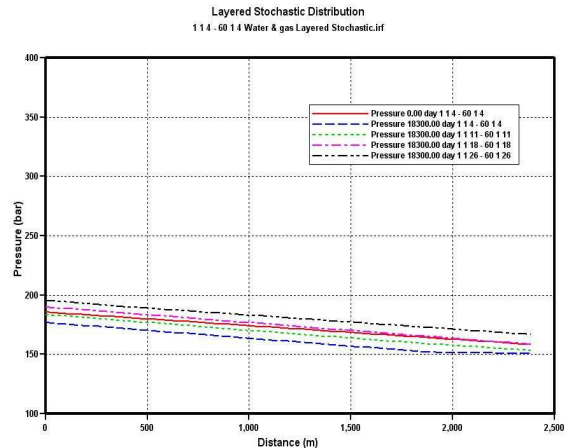


Figure 52: Pressure profile-Layered stochastic reservoir. Pressure gradient=0.06psi/ft

#### 4.1.4. Foam co-injection following surfactant pre-flush and water flooding

In order to investigate the effect of heterogeneity on immiscible foam, simulations were run on the four different reservoir models at the same injection rate and the same producer bottom-hole pressure. Water is injected for 10 years (1.04 PV) and there after a pre-flush of 5 years surfactant flooding with surfactant solution (0.5wt%=0.00028 mole fraction). Surfactant is used as foaming agent and to stabilize foam. Foam co-injection is done for 35 years (4.46 PV), i.e. co-injecting gas and liquid with foam quality of 94%.

Figure 53-56 show oil saturation maps and the foam front after 50 years in the four different reservoir models. Careful examination of the results indicate that homogeneous reservoir has good sweep efficiency as the foam front propagated uniformly towards the producer in all the layers and there is a foam breakthrough at the end of 50 years.

In stochastic permeability reservoir, there is also good sweep efficiency. But the microscopic displacement is poor in all the shaly-sands spots because of very low permeability ( $10^{-3}$  mD). More oil is trapped in those spots due to capillary forces and rock fluid interactions operating on multiple scales. However, foam front advances uniformly in the four layers as well. And at the end of 50 years, foam front has only advanced almost half (1100m) into the reservoir. This indicates the effect of heterogeneity on foam front propagation rate within the reservoir. This also indicates that the rate of foam front propagation is a function of permeability. Therefore, the foam front propagation rate changes over a wide range of permeability distribution as shown in Appendix D (Figure D.1). The average permeability in homogeneous and stochastic reservoir is the same. But the local heterogeneity still play a big role on the foam front propagation rate in stochastic permeability.

A similar trend can be seen in layered reservoir and layered stochastic in which foam front position is a function of permeability. Simulation results show that the first and third layers in both layered reservoir and layered stochastic reservoir have foam breakthrough because of high permeable channels. While the second and fourth layers have the position of foam front 1200m and 400m in layered reservoir, 1148m and 350 m in layered stochastic reservoir respectively at the end of 50 years.

Figure 58 indicates the water cut for each reservoir model, but the water breakthrough time is the same with the base case result (section 4.1) since breakthrough occurred in all the reservoir models before the elapse of 10 years water flooding.

Figure 59 and 60 show that the homogeneous reservoir has the highest oil recovery (65.9%) and much better sweep efficiency than the other three heterogeneous scenarios. Further more the figures show that the stochastic permeability reservoir has the least recovery factor (53.9%) due to low rate foam front propagation within the reservoir. Therefore, more injection time is needed to have a foam breakthrough.

Similarly, layered stochastic reservoir has a lower recovery factor (55.8%) compare with Layered reservoir (57.8%) due to permeability contrast as well. Both layered reservoir and layered stochastic reservoir have an average permeability (812.5mD) far higher than that of homogeneous reservoir (200mD). However, their recovery factors is lower than homogeneous reservoir because of higher permeability channels in first and third layer which leads to early breakthrough those two layers. Therefore, sweep efficiency is poor and hardly increases once displacing fluid has broken through in one of the layers.

Table 6 indicates the difference between 40 years foam co-injection and 40 years NFA. Stochastic permeability appears to have the highest recovery (11.8%) by foam co-injection.

From the pressure profile plot Figure 61-64, show the pressure gradients in all the reservoir models. Homogeneous reservoir has a relatively uniform pressure gradient of 0.23 psi/ft in each layer. Stochastic permeability has two pressure gradients, 0.35 psi/ft behind foam front and 0.09psi/ft ahead of foam front in each layer. Layered reservoir and layered stochastic reservoir have variation in pressure gradient. Layered reservoir has the same pressure gradient 0.18 psi/ft in first and third layers respectively. The second layer (green) has 0.25psi/ft behind foam front and 0.13psi/ft ahead of front while the last layer (black) has behind foam front pressure gradient of 0.66psi/ft and 0.12psi/ft ahead of front.

Layered stochastic reservoir has pressure gradient of 0.17psi/ft in upper layer (blue). The second layer (green) has a pressure gradient of 0.36psi/ft behind foam front and 0.12psi/ft ahead of front, the third layer (purple) has a pressure gradient of 0.18psi/ft and last the layer (black) has a pressure gradient 0.66psi/ft behind foam front and 0.11psi/ft ahead of front.

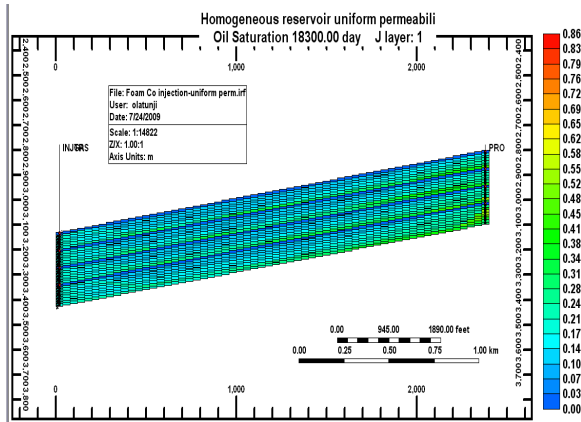


Figure 53: Homogeneous reservoir; Oil saturation map after 10 yrs water flooding, 5yrs surfactant flooding & 35yrs foam co-injection

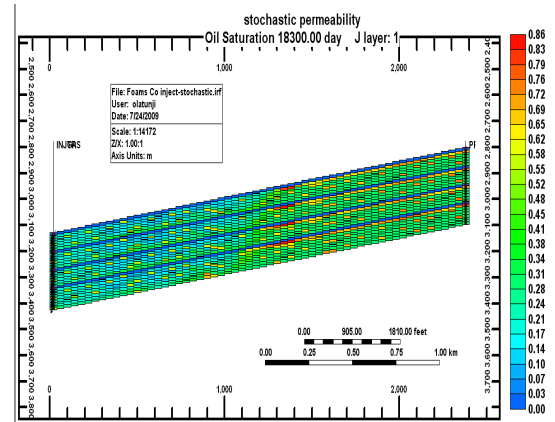


Figure 54: Stochastic permeability reservoir; Oil saturation map after 10yrs water flooding, 5yrs surfactant flooding & 35yrs foam co-injection

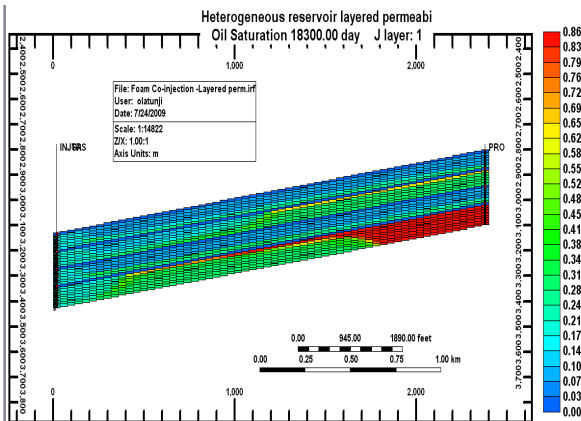


Figure 55: Layered Reservoir; Oil saturation map after 10yrs water flooding, 5yrs surfactant flooding & 35yrs foam co-injection

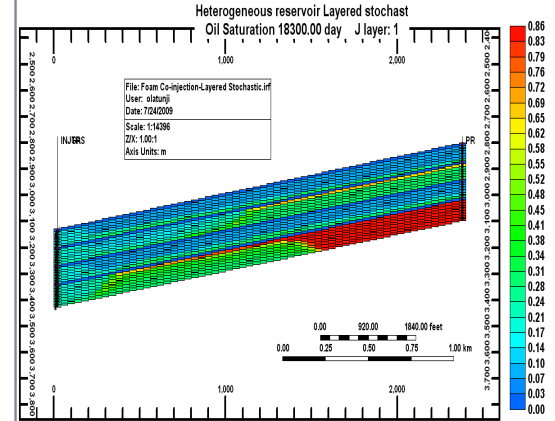


Figure 56: Layered stochastic reservoir; Oil saturation map after 10yrs water flooding, 5yrs surfactant flooding & 35yrs foam co-injection

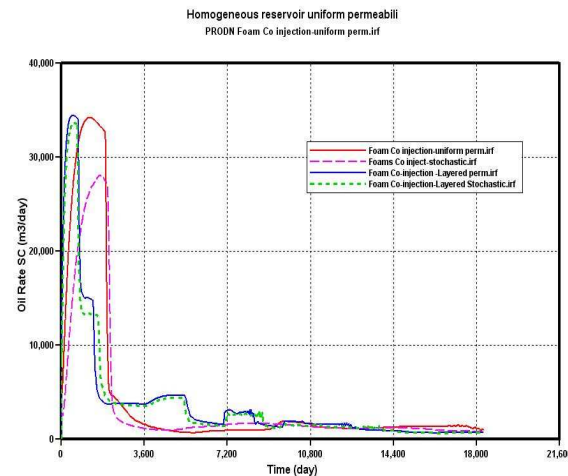


Figure 57: Oil production rate- 10yrs water flooding, 5yrs surfactant flooding & 35yrs foam co-injection (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered-reservoir and (green line) is layered stochastic reservoir

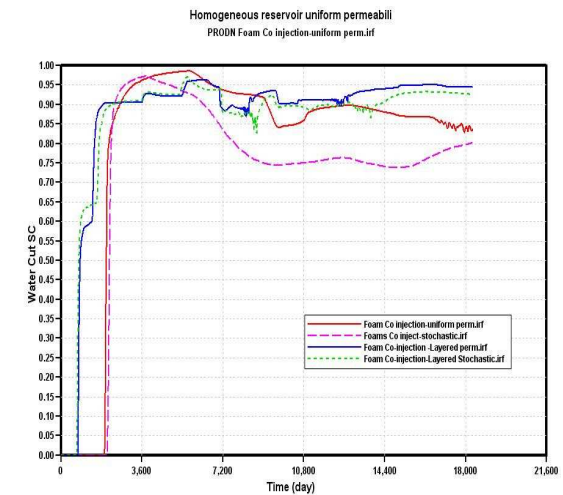


Figure 58: Water Cut- 10yrs water flooding, 5yrs surfactant flooding & 35yrs foam co-injection (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered-reservoir and (green line) is layered stochastic reservoir

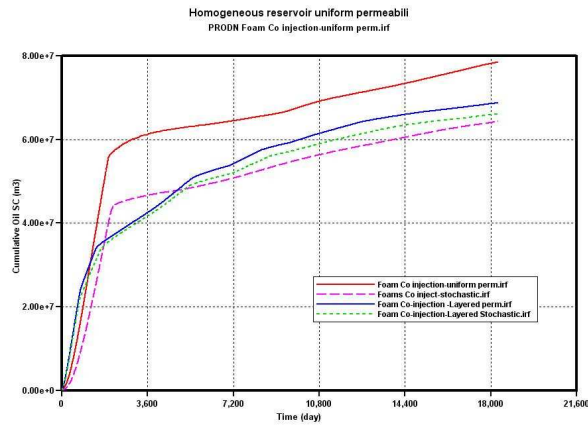


Figure 59: Cumulative Oil production-10 years water flooding, 5yrs surfactant flooding and 35 yrs foam co-injection (red line) is homogeneous reservoir,(purple line) is stochastic permeability reservoir,(blue line) is layered-reservoir and (green line) is layered stochastic.

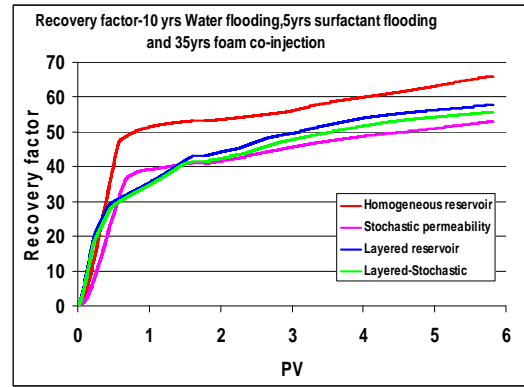


Figure 60: Recovery factor- Water flooding, surfactant flooding and foam co-injection

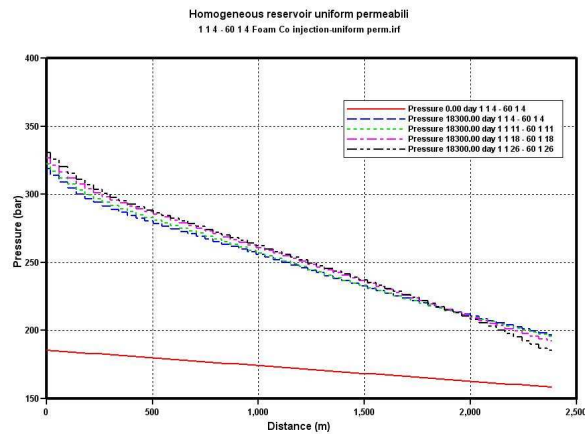


Figure 61: Pressure profile-Homogeneous reservoir after 10 yrs water flooding, 5yrs surfactant flooding & 35yrs foam co-injection pressure gradient=0.23psi/ft.

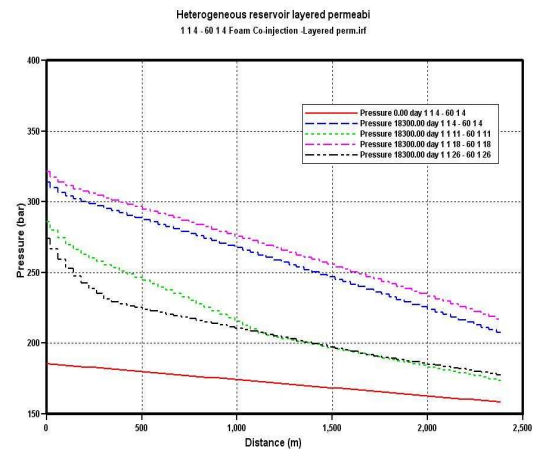


Figure 63: Pressure profile-Layered reservoir after 10 yrs water flooding, 5yrs surfactant flooding & 35yrs foam co-injection pressure gradient in (blue)upper layer=0.18psi/ft second layer(green) have behind foam front=0.25psi/ft & 0.13psi/ft ahead of front, third layer(purple) have 0.18psi/ft and last layer(black) have behind foam front=0.66psi/ft & 0.12psi/ft ahead of front.

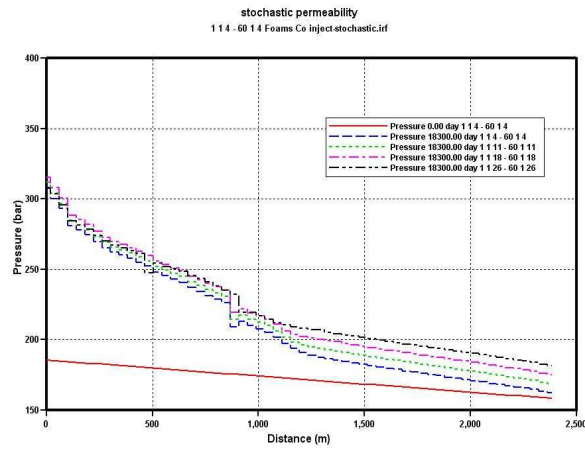


Figure 62: Pressure profile-Stochastic perm reservoir after 10 yrs water flooding, 5 yrs surfactant flooding & 35 yrs foam co-injection pressure gradient behind foam front=0.35psi/ft & 0.09psi/ft ahead of front.

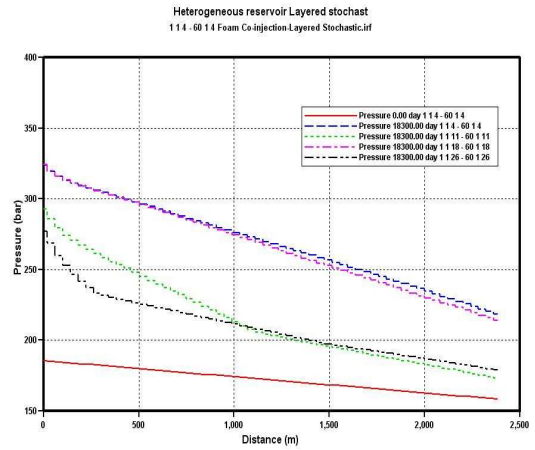


Figure 64: Pressure profile-Layered stochastic reservoir after 10 yrs water flooding, 5 yrs surfactant flooding & 35 yrs foam co-injection pressure gradient in (blue) upper layer=0.17psi/ft second layer (green) have behind foam front=0.36psi/ft & 0.12psi/ft ahead of front, third layer (purple) have 0.18 and last layer (black) have behind foam front=0.66psi/ft & 0.11psi/ft ahead of front.

Table 6: Recovery factor -Water flooding, surfactant flooding & foam co-injection

Different Scenarios	Water flooding RF - 10years	Surfactant Flooding -5 years	Foam injection co-injection -35 years	Total RF after 50 years	Difference between 40 yrs foam co-injection and 40yrs NFA
Homogenous Reservoir 200mD	52.7%	0.4%	12.8%	65.9%	9.4%
Stochastic Distribution 50- 350mD	39.1%	1.7%	13.1%	53.9%	11.8%
Layered Reservoir 2000mD 200mD 1000mD 50mD	35.7%	7.3%	14.8%	57.8%	3.9%
Layered stochastic Distribution 1400-2600mD 100-300mD 600-1400mD 20-80mD	35.1%	6.3%	14.4%	55.8%	4.1%

#### 4.1.5. SAG processes following water flooding

Here is the fifth method of recovery carried out in the study, another way of foam placement in the reservoir by means of SAG (Surfactant-Alternating-Gas) processes. Simulations run on the four different reservoir models at the same injection rate and the same producer bottom-hole pressure. Water is injected for 10 years (1.04 PV) and there after switch to two-cycle SAG processes at ratio 1:2 PV of surfactant to gas.

The simulation results obtained in SAG Processes is apparently similar with foam co-injection results. Figure 65-68 show oil saturation map at the end of SAG processes. Homogeneous reservoir and stochastic reservoir both appeared to have good sweep efficiency as the foam front propagated uniformly in all the layers. Homogeneous reservoir experienced a breakthrough while stochastic permeability is yet to reach breakthrough. The foam front has also advanced 1100 m into the stochastic permeability after 50 years, Simulation results also show that first and third layers in both layered reservoir and layered stochastic reservoir have a breakthrough, while the second and fourth layer have the position of foam front 900m and 300m in layered reservoir, 850m and 250 m in layered stochastic reservoir respectively.

Figure 71 and 72 show that homogeneous reservoir still has the highest oil recovery (65.1%) slightly below the value obtained in co-injection and much better sweep efficiency as well than the other three heterogeneous scenarios.

Table 7 shows that recovery factors for all the reservoir models obtained with SAG processes. They are relatively lower than that obtained with foam co-injection except for stochastic permeability reservoir.

Stochastic permeability reservoir has the least recovery factor (54.1%) due to the wide range permeability distribution and low foam front propagation rate. Therefore more injection time is needed to have a breakthrough. Similarly, layered stochastic reservoir has a lower recovery factor (55.4%) compare with layered reservoir (57.6%) because of permeability contrast. Although, both layered reservoir and layered stochastic reservoir have an average permeability (812.5mD) far higher than homogeneous reservoir (200mD). Their recovery factors is lower than homogeneous reservoir because of higher permeability channels in first and third layer which leads to early breakthrough those two layers. Therefore sweep efficiency is poor and hardly increases once displacing fluid has broken through in one of the layers

From the pressure profile plot Figure 73-76, show the pressure gradients in all the reservoir models. Homogeneous reservoir has a relatively uniform pressure gradient of 0.22 psi/ft in each layer. Stochastic permeability has two pressure gradients, 0.53 psi/ft behind foam front and 0.09psi/ft ahead of foam front in each layer. Layered reservoir and layered stochastic reservoir have variation in pressure gradient. Layered reservoir has the same pressure gradient of 0.14 psi/ft in first and third layers respectively. The second layer (green) have 0.26psi/ft behind foam front and 0.09psi/ft ahead of front while the last layer (black) have pressure gradient of 0.44psi/ft behind foam front and 0.08psi/ft ahead of the front. Layered stochastic reservoir has 0.16psi/ft in (blue) upper layer. The second layer (green) has 0.32psi/ft behind foam front and 0.09psi/ft ahead of front. The third layer (purple) has 0.15psi/ft and last layer (black) has 0.33psi/ft behind foam front and 0.09psi/ft ahead of front.

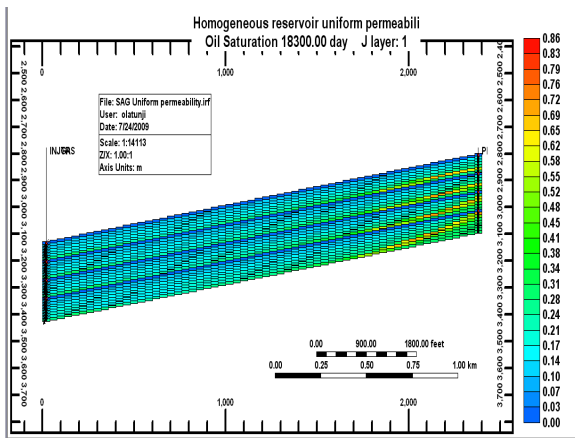


Figure 65: Homogeneous Reservoir; Oil saturation map after 10yrs water flooding & 40yrs SAG Process

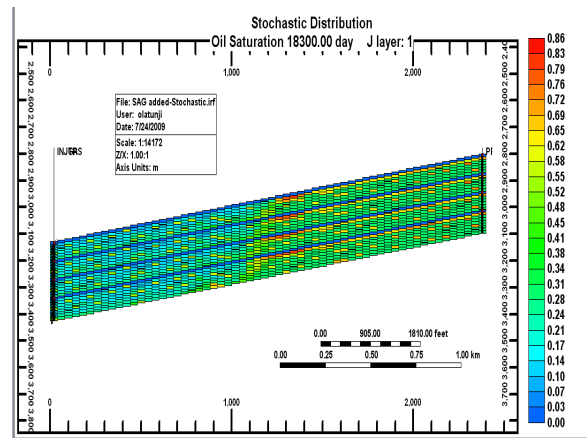


Figure 66: Stochastic perm. Reservoir; Oil saturation map after 10yrs water flooding & 40yrs SAG Process

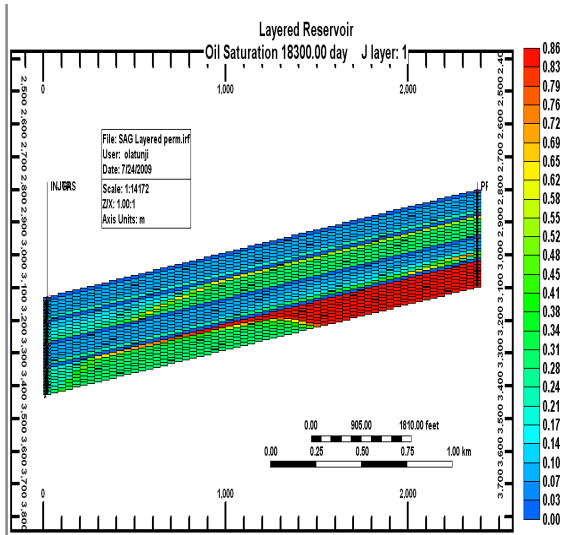


Figure 67: Layered reservoir; Oil saturation map after 10yrs water flooding & 40yrs SAG process

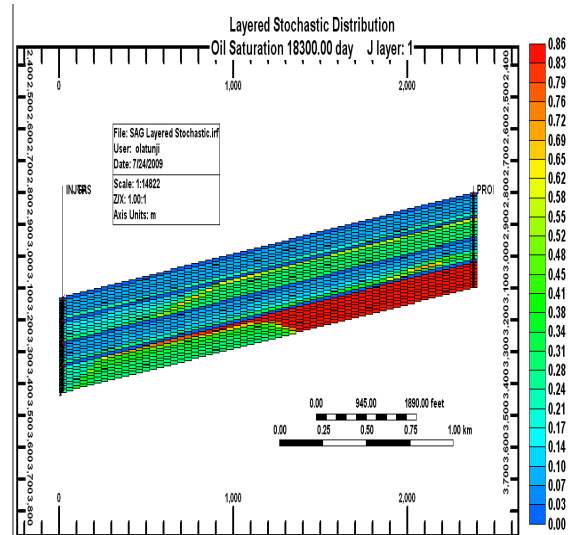


Figure 68: Layered stochastic reservoir; Oil saturation map after 10yrs water flooding & 40yrs SAG process

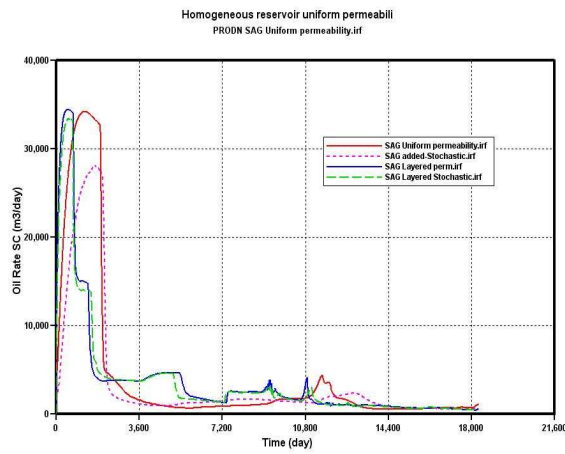


Figure 69: Oil production rate -10 years Water flooding & SAG process for 40 years, (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered-reservoir and (green line) is layered stochastic

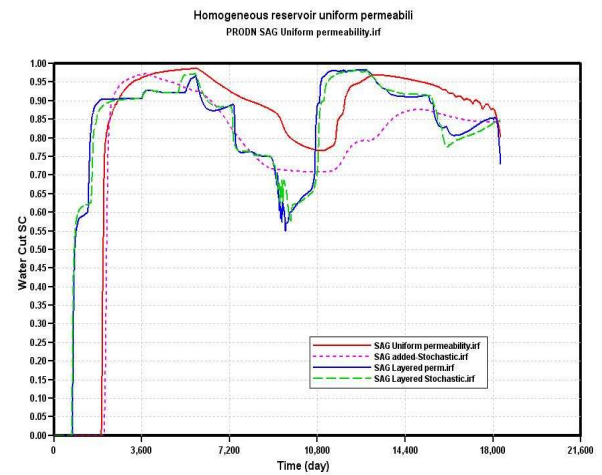


Figure 70: Water cut -10 years Water flooding & SAG process for 40 years.

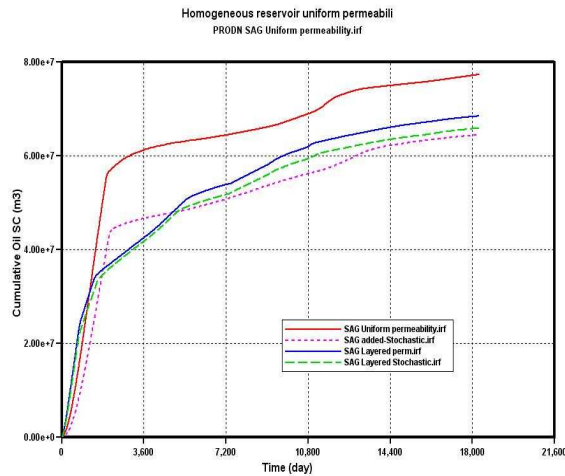


Figure 71: Cumulative Oil production-10 years Water flooding & SAG Process for 40 yrs, (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered reservoir and (green line) is layered stochastic

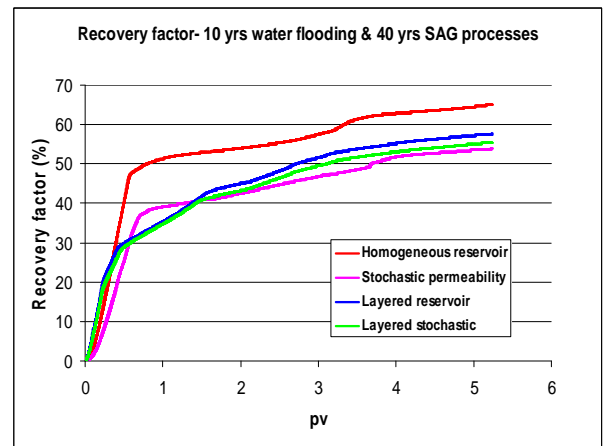


Figure 72: Recovery factor -10 yrs Water flooding and 40yrs SAG processes

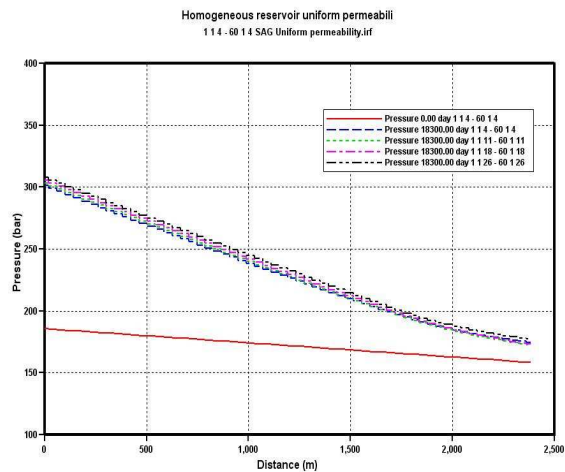


Figure 73: Pressure profile-Homogeneous reservoir after 10 yrs water flooding & 40yrs SAG processes, pressure gradient=0.22psi/ft

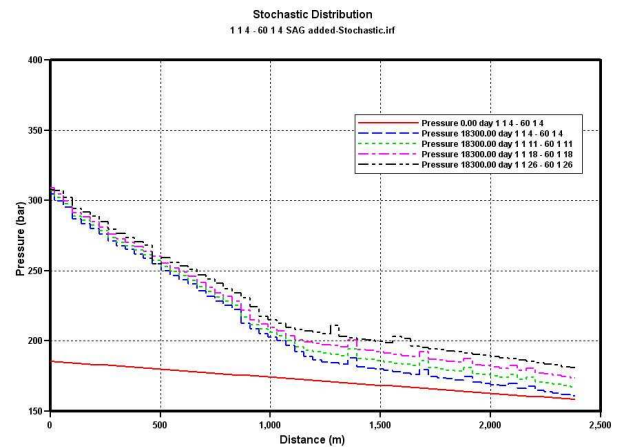


Figure 74: Pressure profile-Stochastic perm reservoir after 10 yrs water flooding & 40yrs SAG processes. pressure gradient behind foam front=0.53psi/ft & 0.09psi/ft ahead of front

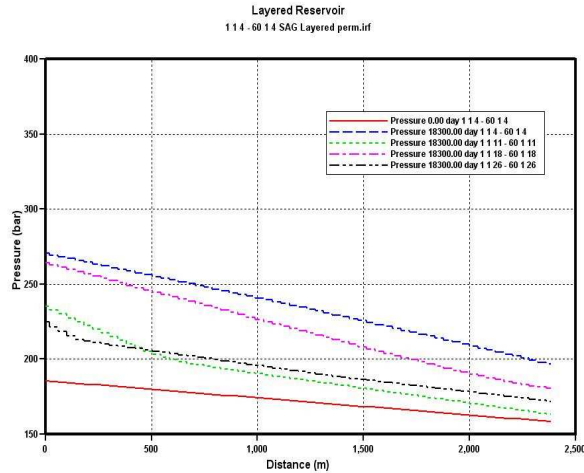


Figure 75: Pressure profile-Layered reservoir after 10 yrs water flooding and 40yrs SAG processes, pressure gradient in (blue)upper layer=0.14psi/ft, second layer(green) have behind foam front=0.26psi/ft and 0.09psi/ft ahead of front, third layer(purple)have 0.16psi/ft and last layer(black) have behind foam front=0.44psi/ft and 0.08psi/ft ahead of front

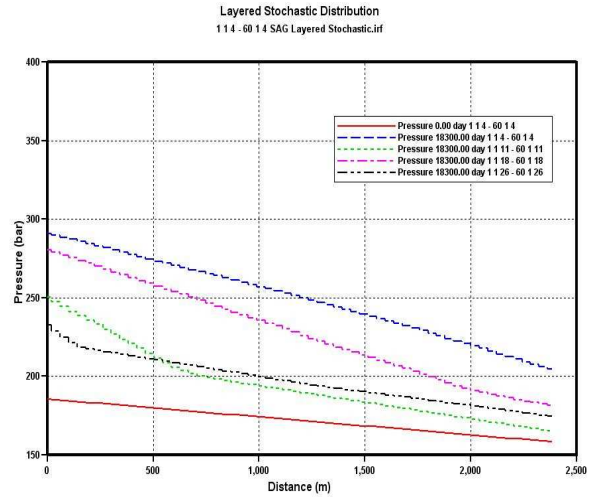


Figure 76: Pressure profile-Layered stochastic after 10 yrs water flooding and 40yrs SAG processes, pressure gradient in (blue)upper layer=0.16psi/ft, second layer(green) have behind foam front=0.32psi/ft and 0.09psi/ft ahead of front, third layer(purple)have 0.15psi/ft and last layer(black) have behind foam front=0.33psi/ft and 0.09psi/ft ahead of front

**Table 7: Recovery factor -Water flooding & SAG Processes**

Different Scenarios	Water flooding RF - 10years	SAG Process RF- 40 years	Total RF after 50 years	Difference between 40 years SAG processes and 40yrs NFA
Homogenous Reservoir 200mD	52.7%	12.4%	65.1%	8.6%
Stochastic Distribution 50- 350mD	39.1%	15.0%	54.1%	12.0%
Layered Reservoir 2000mD 200mD 1000mD 50mD	35.7%	21.9%	57.6%	3.7%
Layered stochastic Distribution 1400-2600mD 100-300mD 600-1400mD 20-80mD	35.1%	20.3%	55.4%	3.7%

#### **4.1.6. WAG processes following water flooding**

Water is injected for 10 years and then switch to WAG processes. During the WAG process, water and nitrogen gas are intermittently injected at 90 days cycle for 40 years.

Figure 77-80 show oil saturation maps at the end of WAG processes. Homogeneous reservoir still appeared to have the better sweep efficiency than other reservoir models. Careful examination of this saturation map revealed that the mixed zone is within 400m to injector and there after a segregation zone with only gas flowing in the override zone and water only in the underride zone.

In stochastic permeability reservoir, the mixed zone is also within 400m to the injector. Due to permeability contrast and low propagation rate as well, the segregated zones only covered half (1100m) of the reservoir. Saturation maps also show that the first and third layers in both layered reservoir and layered stochastic reservoir experienced early breakthrough of gas in the override zone and water in the underride zone. While the second and fourth layer have the positions of segregated zones up to 850m and 250m in layered reservoir, 800m and 250 m in layered stochastic reservoir respectively.

Figure 83 and 84 show that homogeneous reservoir still has the highest oil recovery (62.8%). Stochastic permeability reservoir has the least recovery factor (49.5%).

Similarly, layered stochastic reservoir has a lower recovery factor (53.2%) compare with layered reservoir (54.0) because of permeability contrast.

From the pressure profile plot Figure 85-88, show the pressure gradients in all the reservoir models. Homogeneous reservoir has a uniform pressure gradient of 0.61 psi/ft in the mixed zone and 0.24psi/ft in the segregated zones. Stochastic permeability has a two pressure gradients, 0.74 psi/ft behind WAG front and 0.28psi/ft ahead of WAG front in each layer. It is also observed pressure pulses on some shaly-sand spots with low permeability. There is a pressure gradient variation in both layered reservoir and layered stochastic reservoir. Layered reservoir has a different pressure gradient of 0.19psi/ft in upper layer. The second layer has a pressure gradient in the mixed zone of 0.17psi/ft and 0.11psi/ft in the segregated zone. The third layer has a pressure gradient of 0.16psi/ft and last layer has a pressure gradient in the mixed zone of 0.44psi/ft and 0.08psi/ft in the segregated zone.

Layered stochastic reservoir has pressure gradient in upper layer of 0.20psi/ft. The second layer has a pressure gradient in the mixed zone of 0.29psi/ft and 0.11psi/ft in the segregated zone. The third layer has pressure gradient of 0.18psi/ft and last layer a pressure gradient in the mixed zone 0.33psi/ft and 0.10psi/ft in the segregated zone.

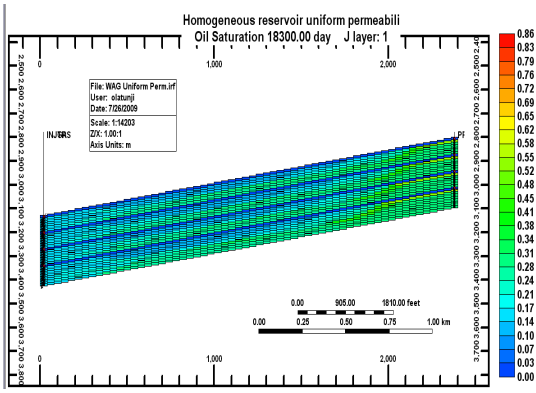


Figure 77: Homogeneous reservoir-Oil saturation map after 10yrs water flooding & 40yrs WAG Process

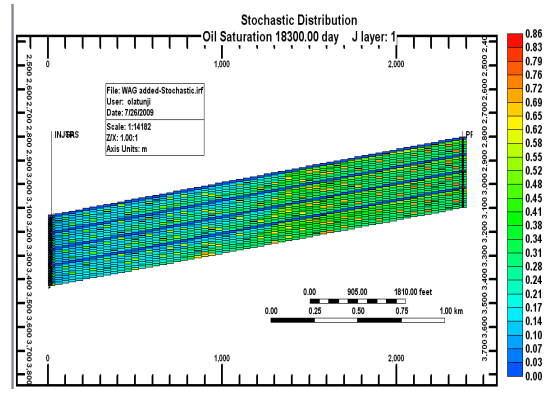


Figure 78: Stochastic perm. Reservoir-Oil saturation map after 10yrs water flooding & 40yrs WAG Process

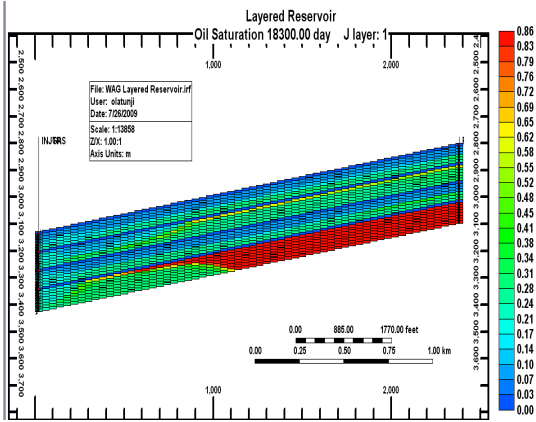


Figure 79: Layered reservoir; Oil saturation map after 10yrs water flooding & 40yrs WAG Process

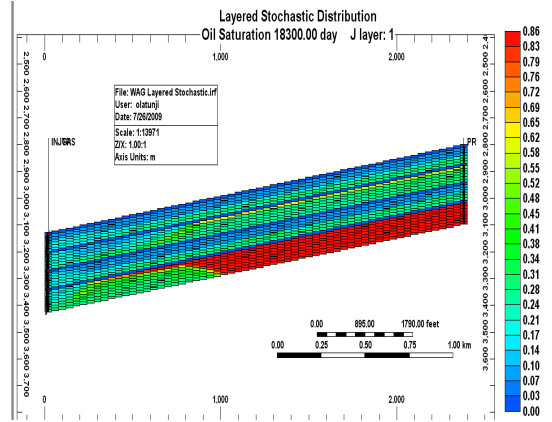


Figure 80: Layered stochastic reservoir; Oil saturation map after 10yrs water flooding & 40yrs WAG Processes

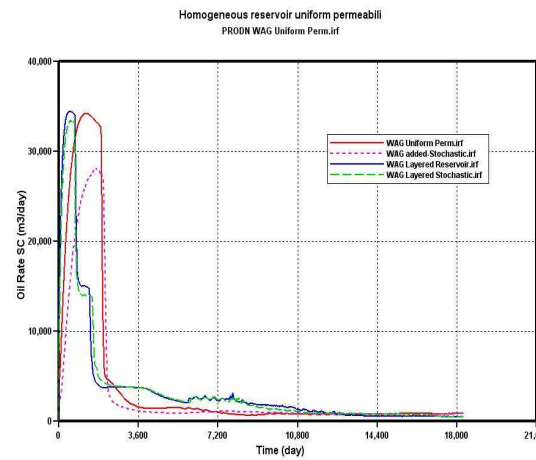


Figure 81: Oil production rate -10 years Water flooding & 40yrs WAG Process, (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered-reservoir and (Green line) is layered stochastic

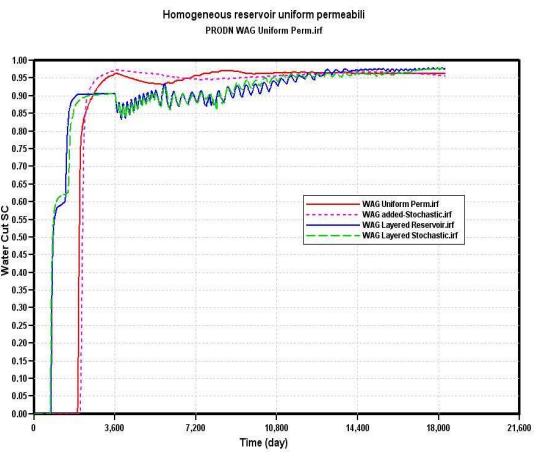


Figure 82: Water cut -10 years Water flooding & 40yrs WAG Process, (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered-reservoir and (green line) is layered stochastic

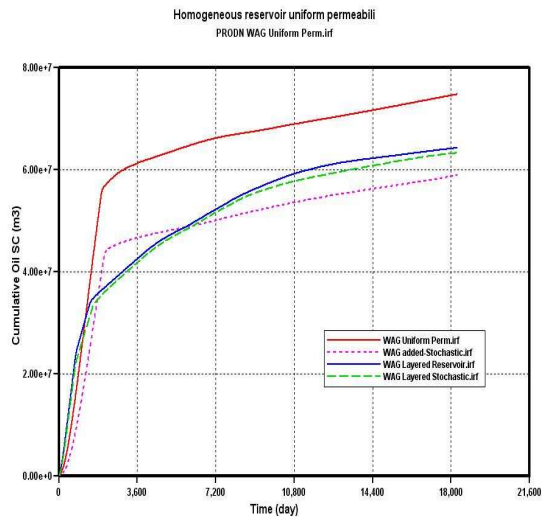


Figure 83: Cumulative Oil production-10 years Water flooding & WAG Process for 40 years, (red line) is homogeneous reservoir, (purple line) is stochastic permeability reservoir, (blue line) is layered-reservoir and (green line) is layered stochastic

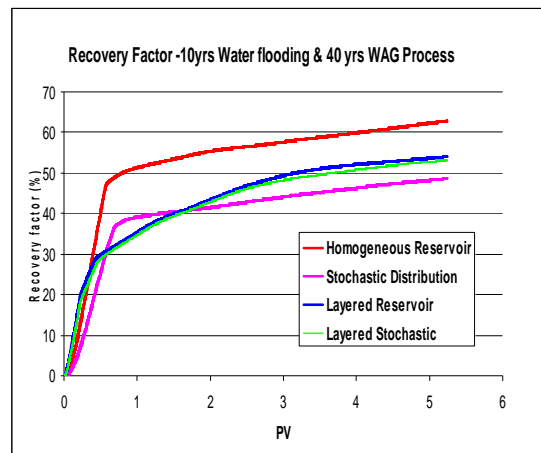


Figure 84: Recovery factor -Water flooding and WAG Processes

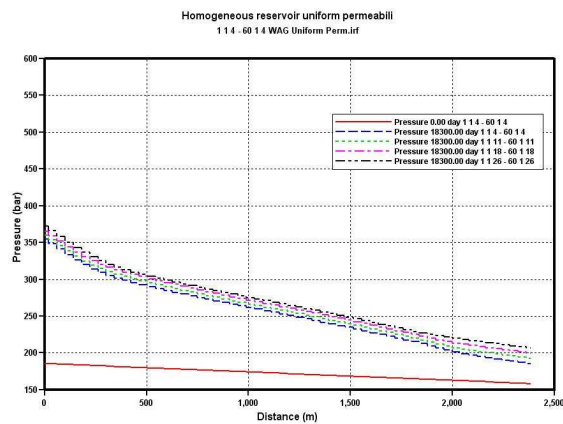


Figure 85: Pressure profile-Homogeneous reservoir after 10 years water flooding and 40 years WAG processes, pressure gradient close to injection well 0.61psi/ft and further away 0.24psi/ft

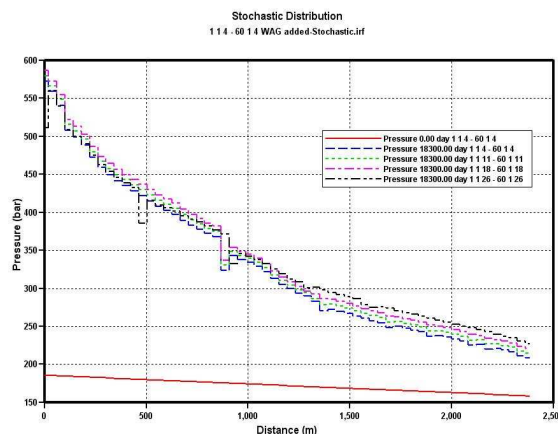


Figure 86: Pressure profile-Stochastic perm reservoir after 10 years water flooding and 40 years WAG processes. Pressure gradient =0.74psi/ft behind WAG front and 0.28psi/ft ahead of WAG front

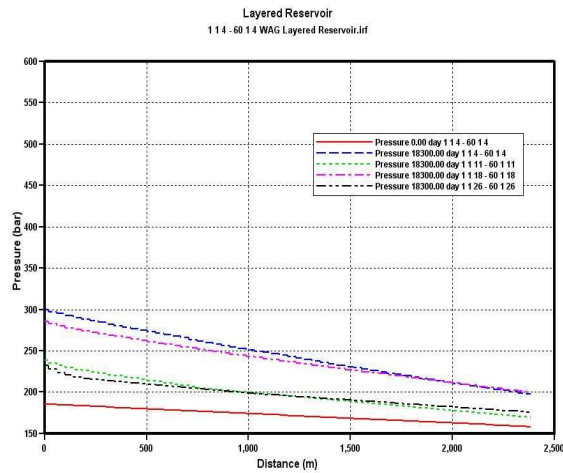


Figure 87: Pressure profile-Layered reservoir after 10 years water flooding and 40 years WAG processes, pressure gradient in (blue) upper layer=0.19psi/ft, second layer (green) have behind WAG front=0.17psi/ft and 0.11psi/ft ahead of front, third layer (purple) have 0.16psi/ft and last layer (black) have behind foam front=0.44psi/ft and 0.08psi/ft ahead of front

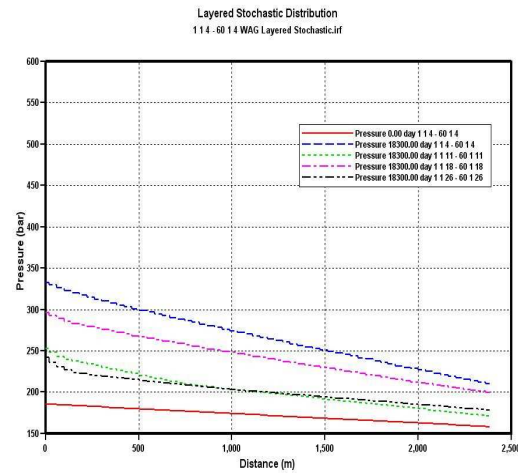


Figure 88: Pressure profile-Layered stochastic after 10 years water flooding and 40 years WAG processes, pressure gradient in (blue) upper layer=0.20psi/ft, second layer (green) have behind foam front=0.29psi/ft and 0.11psi/ft ahead of front, third layer (purple) have 0.18psi/ft and last layer (black) have behind foam front=0.33psi/ft and 0.10psi/ft ahead of front

**Table 8: Recovery Factor - Water flooding & WAG Processes**

Different Scenarios	Water flooding RF - 10years	WAG Process RF- 40 years	Total RF after 50 years	Increase RF- Effect of WAG
Homogenous Reservoir 200mD	52.7%	10.1%	62.8%	6.3%
Stochastic Distribution 50- 350mD	39.1%	10.4%	49.5%	7.4%
Layered Reservoir 2000mD 200mD 1000mD 50mD	35.7%	18.3%	54.0%	0.1%
Layered stochastic Distribution 1400-2600mD 100-300mD 600-1400mD 20-80mD	35.1%	18.1%	53.2%	1.5%

## 4.2. Comparism of injection scenarios

Figure 89-92 compare the oil recovery factor of different injection scenarios on all the reservoir models. Foam co-injection scenario appeared apparently to have the highest recovery in all the reservoir models. And the sweep efficiency is best among other injection scenarios. Table 9 indicates foam co-injection produces three times more oil than that of gas injection in all the reservoir models except for stochastic permeability.

However, SAG processes recovery factors follow closely with the co-injection scenario in all the reservoir models. And this appeared the second best in term of recovery and sweep efficiency among other scenarios.

Comparing 40 years gas injection with 40 years foam injection (both co-injection and SAG) in table 9 .The results confirm that the use of foam greatly reduces gas mobility and the effect of reservoir heterogeneity and therefore improve sweep efficiency.

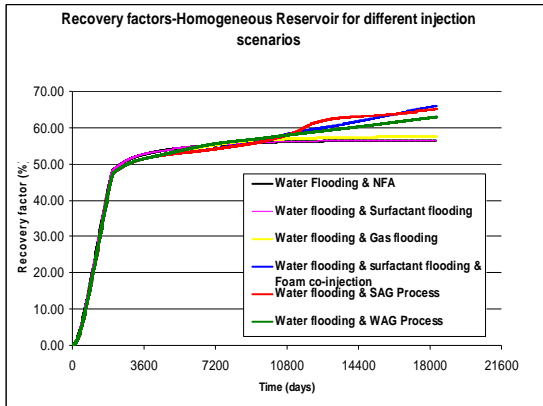


Figure 89: Recovery factors –Homogeneous reservoir for different injection scenarios

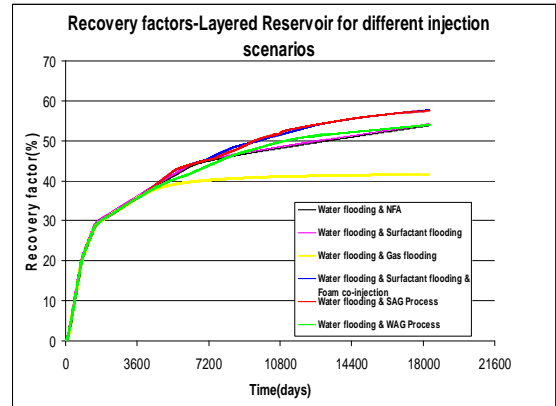


Figure 91: Recovery factors –Layered reservoir for different injection scenarios

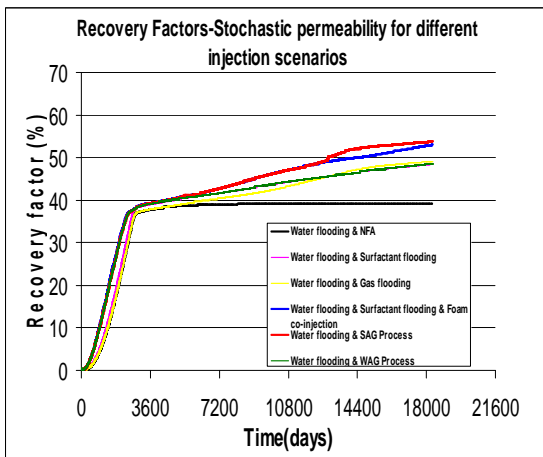


Figure 90 Recovery factors –Stochastic permeability for different injection scenarios

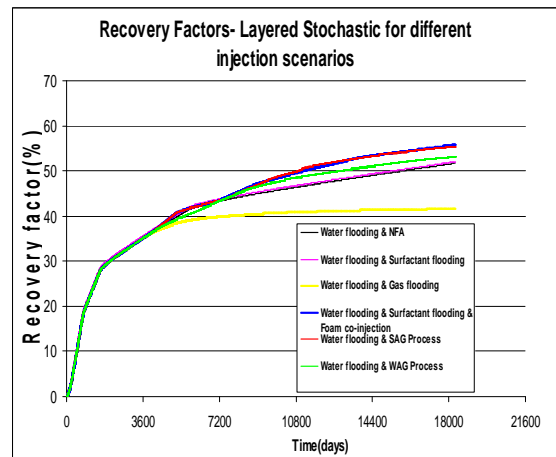


Figure 92: Recovery factors –Layered stochastic for different injection scenarios

**Table 9 Incremental recoveries with respect to 40 years NFA**

Different Scenarios	Surfactant flooding -40 years	Gas flooding -40 years	Foam co-injection -40 years	SAG processes - 40 years	WAG processes -40 years	Remarks
Homogenous reservoir 200mD	0.1%	1.1%	9.4%	8.6%	6.3%	
Stochastic distribution 50- 350mD	6.8%	8.2%	13.8%	12.0%	7.4%	
Layered reservoir 2000mD 200mD 1000mD 50mD	0.3%	-12.3%	3.9%	3.7%	0.1%	Negative value indicates that NFA recovery is higher than gas recovery
Layered stochastic distribution 1400-2600mD 100-300mD 600-1400mD 20-80mD	0.3%	-10.1%	4.1%	3.7%	1.5%	Negative value indicates that NFA recovery is higher than gas recovery

**Table 10 Summary of total recovery factors for all injection scenarios at the end of 50 years**

Different Scenarios	Water flooding & NFA - 50years	Surfactant flooding follow by water flooding-50 years	Gas flooding follow by water flooding-50 years	Foam co-injection follow by surfactant preflush follow by water flooding-50 years	SAG processes follow by water flooding-50 years	WAG processes follow by water flooding-40 years
Homogenous reservoir 200mD	56.5%	56.6%	57.6%	65.9%	65.1%	62.8%
Stochastic distribution 50- 350mD	42.1%	48.9%	50.3%	53.9%	54.1%	49.5%
Layered reservoir 2000mD 200mD 1000mD 50mD	53.9%	54.2%	41.6%	57.8%	57.6%	54.0%
Layered stochastic distribution 1400-2600mD 100-300mD 600-1400mD 20-80mD	51.7%	52.0%	41.6%	55.8%	55.4%	53.2%

### **4.3. Sensitivity analysis on oil viscosity**

To examine the influence of oil viscosity on the performance of immiscible foam, a sensitivity analysis is done, by using higher viscous oil of 8.28cP. While other fluid properties and foam parameters remain the same. Simulations were run for all the injection scenarios.

Appendix E shows the simulation results for all the injection scenarios. In all cases sweep efficiency decrease and consequently reduce recovery factors as a result of higher viscous oil.

In the first phase of 10 years water flooding, there is severe underride and viscous fingers because the viscosity of water is much more less than that of the oil. The same trend occurred during NFA and surfactant flooding. Gas injection is even worse because gas density and viscosity is much lower than oil and water densities therefore gas overrides the oil and leading to early gas breakthrough. Foam co-injection, SAG processes and WAG processes reduce all the negative effects and a higher recovery factors were obtained as indicated in the tables. However, in all cases recovery factors decrease due to high oil viscosity and couple with reservoir heterogeneity as the case may be.

# Chapter 5

## Conclusions and recommendations

### 5.1 Conclusions

- Homogeneous reservoir has the highest sweep efficiency and highest recovery factor for all the different injection scenarios.
- Stochastic permeability reservoir has the least recovery factor due to the wide range permeability distribution and low foam front propagation rate. Therefore more injection time is needed to have a breakthrough
- From results obtained, heterogeneity reduces the foam front propagation rate within the reservoir, therefore delay in breakthrough time.
- More oil is trapped in heterogeneous reservoirs at the end of the simulations especially the low permeability ( $10^{-3}$  mD) spots. due to capillary forces and rock fluid interactions operating on multiple scale
- The layer with the lowest permeability (50mD) in both layered reservoir and layered stochastic reservoir is hardly swept, irrespective of the injection scenario. Because of occurrence of early breakthrough in higher permeability channels in first and third layer.
- Pressure gradient in homogeneous reservoir is uniform in each layer. While in all the heterogeneous models there is variations in pressure gradient due to permeability contrasts
- By comparing 40years of all the different injection scenarios, foam injection did a better sweep efficiency because of its apparent viscosity more than that of water flooding. And also a better microscopic displacement efficiency than the others means of recovery, because surfactant (pre-flush) lower the IFT between oil and water and allow easier spreading
- SAG processes recovery factor is relatively lower than that obtained with Foam co-injection except for stochastic permeability reservoir.
- Increase of oil viscosity in the sensitivity analysis, leads to decrease in sweep efficiency and lower recovery factor with all the injection scenarios.
- The results confirm that the use of foam greatly reduces gas mobility and the effect of reservoir heterogeneity and therefore improve sweep efficiency.

## 5.2 Recommendations

- Incorporating the effect of cross flow into the reservoir models to investigate the effect of heterogeneity on immiscible foam EOR.
- Incorporate in STARS<sup>TM</sup> the effect of high capillary number on reduction of residual oil saturation.

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## Appendix A: Foam interpolation functions

$$K_{rg}^f = K_{rg}^o FM$$

$$FM = \frac{1}{(1 + FMMOB F1 F2 F3 F4 F5 F6)}$$

*FMMOB* reference mobility-reduction factor

*F1* surfactant-mole fraction -dependent function

*F2* oil-Saturation-dependent function

*F3* capillary-number-dependent function

*F4* critical-capillary-number-dependent function

*F5* critical-oil mole fraction-dependent function

*F6* Salt-mole fraction-dependent function

In this study, only the following functions and parameters are considered: *FMMOB*, *F1*, *F2* and *F3*. The functions not considered (*F4*, *F5* and *F6*) were set equal to 1.

- a. *FMMOB* corresponds to the normalized resistance to flow of minimum size bubble, in the absence of factors increasing bubble size
- b. *F1* surfactant-mole fraction-dependent function

$$F1 = \left( \frac{W_s}{fmsurf} \right)^{epsurf}$$

$W_s$  : surfactant mole fraction in the grid block.

*fmsurf*: critical surfactant mole fraction.

*epsurf* : parameter that controls the gas mobility's dependence on surfactant mole fraction.

The first interpolation function based on surfactant mole fraction (*F1*) defines a Surfactant mole fraction (*fmsurf*) such that if the actual surfactant mole fraction  $W_s$  is lower than *fmsurf*, then  $F1 < 1$  and in the opposite case,  $F1 = 1$ . If the surfactant mole fraction ( $W_s$ ) falls below *fmsurf*, the mobility reduction factor will be lower, scaled down by *epsurf*. If it is above *fmsurf*, it will be one, for there is no possibility of having more than maximum mobility reduction factor.

**c. F2** oil-Saturation-dependent function

$$F2 = \left( \frac{fmoil - S_o}{fmoil - floil} \right)^{epoil}$$

$S_o$  : oil saturation in grid block

**fmoil**: maximum oil saturation for stable foam

**floil**: Lower oil saturation used in foam interpolation calculation

**epoil**: parameter that decides the oil concentration's affect on *FM*

The second foam interpolation function (*F2*) describes the effect of oil on foam behavior. Above certain oil saturation (**fmoil**) the foam will be completely destroyed by oil and there will be no mobility reduction. Below that limit, the foam will be partially destabilized in the presence of oil, and foam mobility will be reduced according to a power law with exponent *epoil*.

**d. F3**, Capillary-number-dependent function

$$F3 = \left( \frac{fmcap}{capillary\ number} \right)^{epcap}$$

**fmcap**: capillary number for reference foam

**epcap**: exponent that controls the capillary number's affect on *FM*

The capillary number is a function of pressure gradient, and the foam gets weaker as pressure gradient increases. The definition of capillary number used in STARS™ is  $(K_{abs} \nabla P / \sigma_{wg})$ . In this study the function *F3*, using capillary number, has been used to model shear thinning.

**e. F4**, critical-capillary-number-dependent function

$$F4 = \left( \frac{fmgcp - capillary\ number}{fmgcp} \right)^{epgcp}$$

**fmgcp**: critical capillary number for foam generation

**epgcp**: exponent which controls the critical capillary number's affect on *FM*

This function has not been examined in this study.

**f. F5** ,critical-oil mole fraction-dependent function

$$F5 = \left( \frac{fmomf - S_{omf}}{fmomf} \right)^{epomf}$$

$S_{omf}$  : oil mole fraction in liquid phase in grid block

$fmomf$ : critical oil mole fraction in liquid phase

$epomf$ : exponent for oil mole fraction contribution to foam interpolation

This function has not been further examined in this study.

**g. F6**, Salt-mole fraction-dependent function

$$F6 = \left( \frac{H_{salt} - flsalt}{fmsalt - flsalt} \right)^{epsalt}$$

$H_{salt}$  : salt mole fraction in aqueous phase

$fmsalt$ : critical salt mole fraction value

$flsalt$  : lower salt mole fraction value

$epsalt$ : exponent for salt contribution to foam interpolation

This function has not been further examined in this study.

## Appendix B: Water-oil relative permeability & Liquid-Gas relative permeability and IFT table

Table B.1: Water-oil relative permeability

$S_w$	$K_{rw}$	$K_{row}$
0.149	0	1
0.24	0.006	0.768
0.289	0.008	0.454
0.361	0.038	0.224
0.478	0.107	0.068
0.524	0.182	0.031
0.647	0.355	0
1.0	1.0	0

Table B.2: Liquid-gas relative permeability

$S_w$	$K_{rg}$	$K_{rog}$
0.15	1	0
0.34	0.4	0.0009
0.46	0.25	0.009
0.64	0.095	0.09
0.76	0.04	0.22
0.88	0.01	0.49
1.0	0	1

### IFT Table

Mole Frac	IFT (mN/m)
<b>0.</b>	<b>50</b>
<b>0.00028</b>	<b>1</b>

## Appendix C: Oil saturation maps and profiles for 10 years water flooding (1.04 PV)

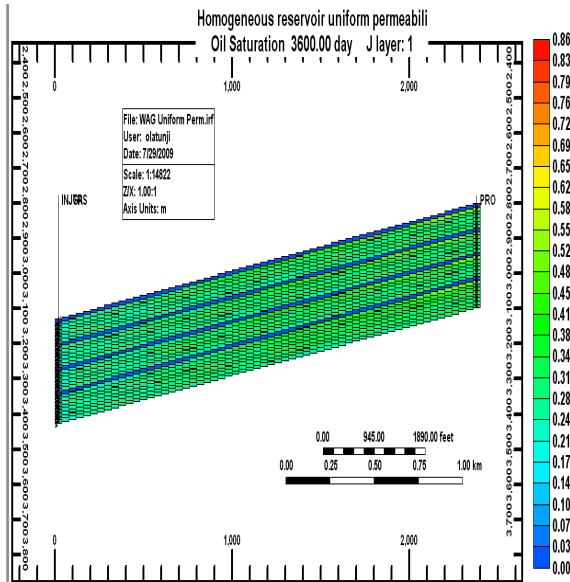


Figure C.1 Homogeneous reservoir- Oil saturation maps for 10 years water flooding (1.04 pv)

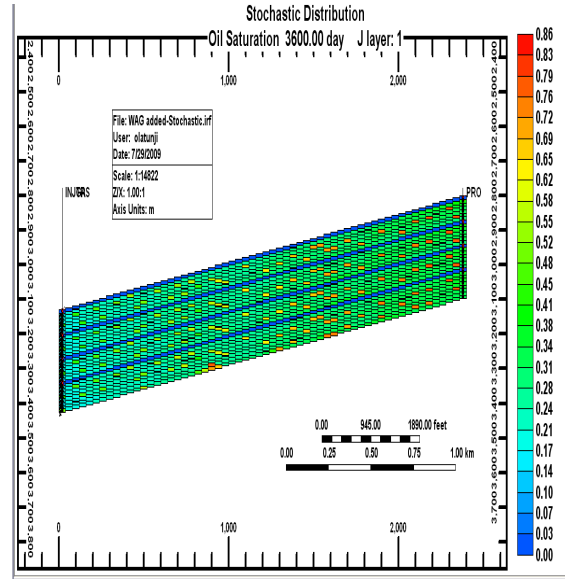


Figure C.2 Stochastic permeability- Oil saturation maps for 10 years water flooding (1.04 pv)

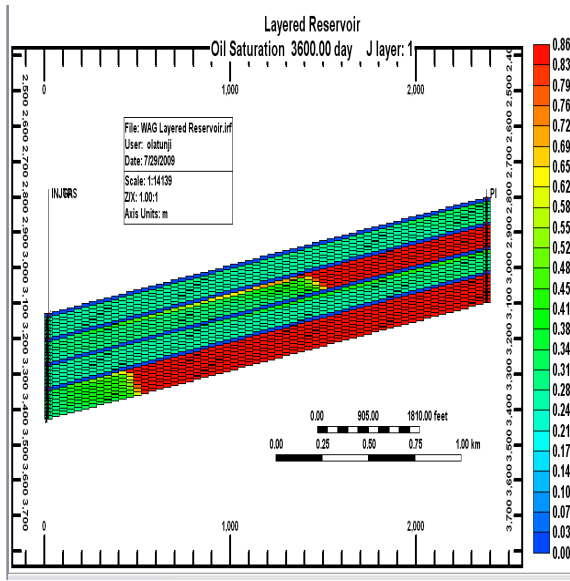


Figure C.3 Layered reservoir- Oil saturation maps for 10 years water flooding (1.04 pv)

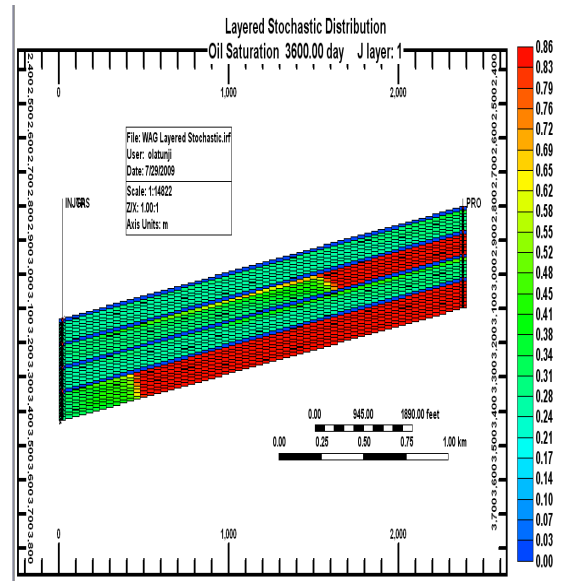


Figure C.4 Layered stochastic- Oil saturation maps for 10 years water flooding (1.04 pv)

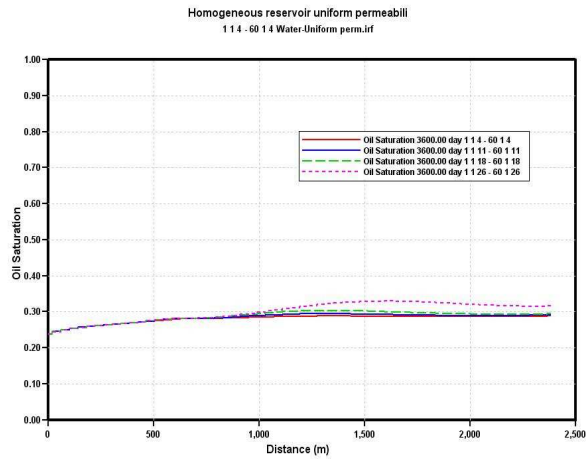


Figure C.5 Homogeneous reservoir, Oil saturation profile after 10 years water flooding. (Red line) is upper layer, (blue line) is second layer, (green line) is third layer and (purple line) is last Layer

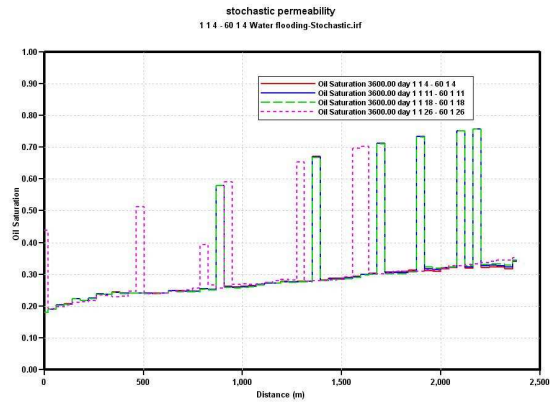


Figure C.6 Stochastic permeability, Oil saturation profile after 10 years water flooding. (Red line) is upper layer, (blue line) is second layer, (green line) is third layer and (purple line) is last Layer

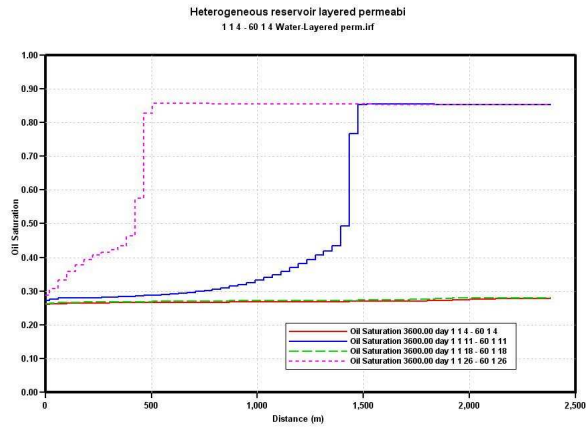


Figure C.7 Layered reservoir, Oil saturation profile after 10 years water flooding. (Red line) is upper layer, (blue line) is second layer, (green line) is third layer and (purple line) is last Layer

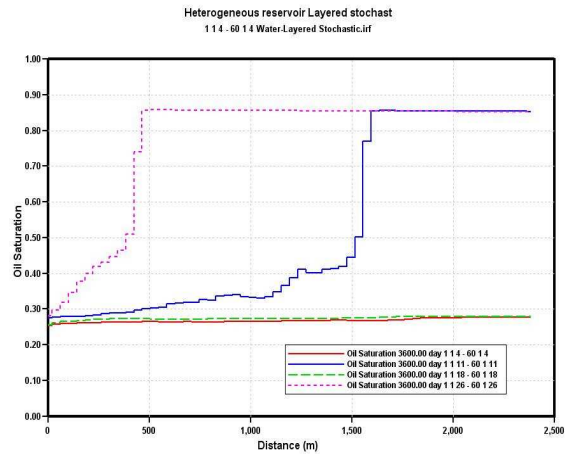


Figure C.8 Layered stochastic, Oil saturation profile after 10 years water flooding. (Red line) is upper layer, (blue line) is second layer, (green line) is third layer and (purple line) is last Layer

## Appendix D: Stochastic permeability distribution

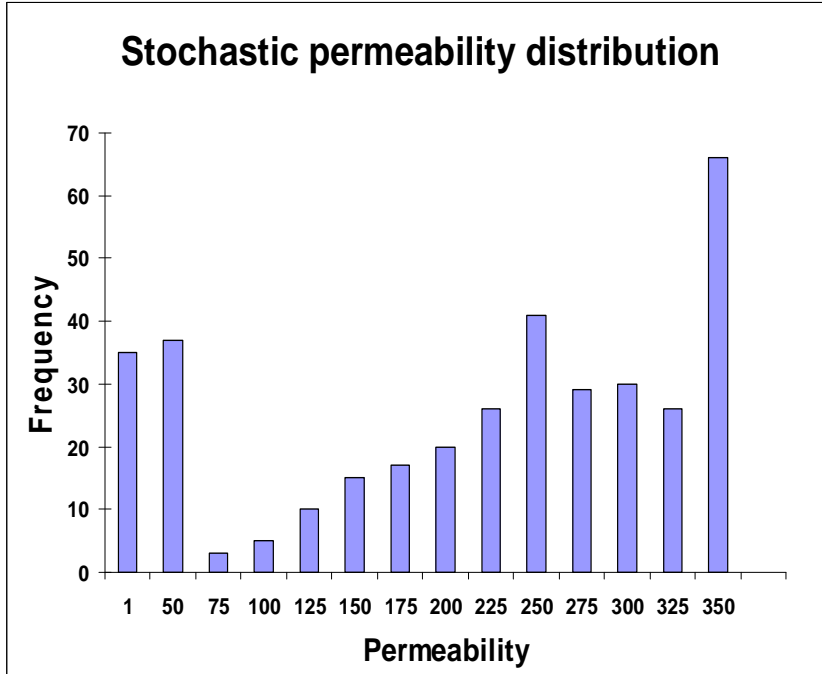


Figure D.1. Stochastic permeability distribution

## Appendix E: Sensitivity analysis for higher oil viscosity

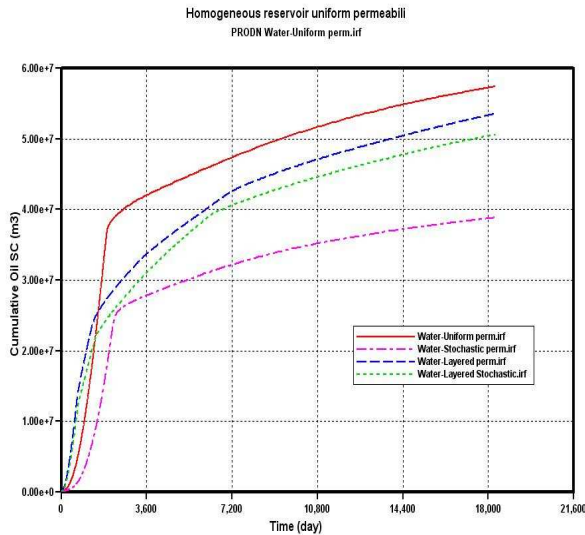


Figure E.1 Cumulative oil production for water flooding & NFA (higher oil viscosity). Homogeneous (red line), stochastic permeability (purple line), layered reservoir (blue line) and layered stochastic (green line)

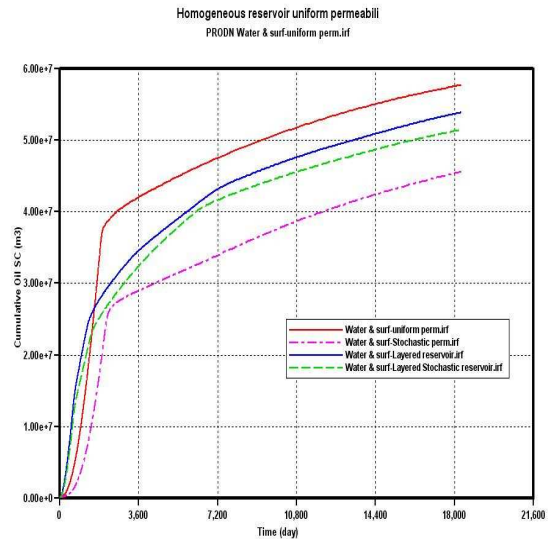


Figure E.2 Cumulative oil production for Surfactant flooding following water flooding (higher oil viscosity) Homogeneous (red line), stochastic permeability (purple line), layered reservoir (blue line) and layered stochastic (green line)

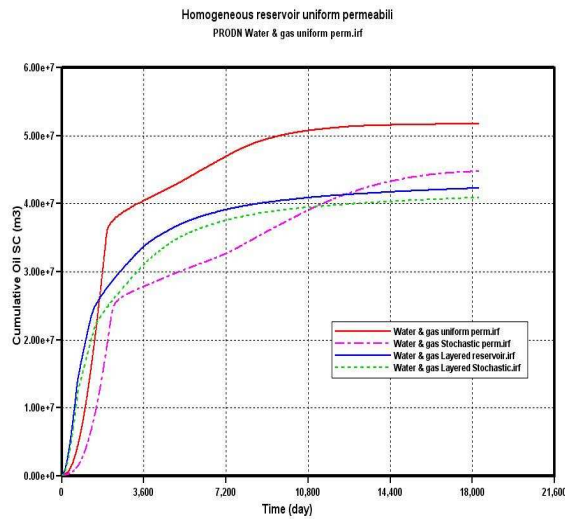


Figure E.3 Cumulative oil production for gas injection following water flooding (higher oil viscosity) Homogeneous (red line), stochastic permeability (purple line), layered reservoir (blue line) and layered stochastic (green line)

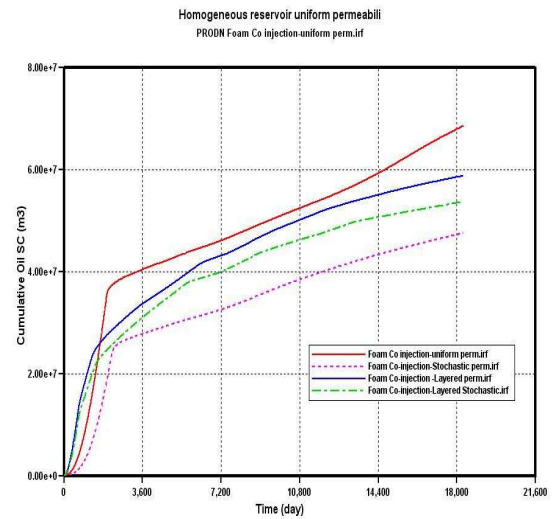


Figure E.4 Cumulative oil production for foam co-injection following water flooding (higher oil viscosity) Homogeneous (red line), stochastic permeability (purple line), layered reservoir (blue line) and layered stochastic (green line)

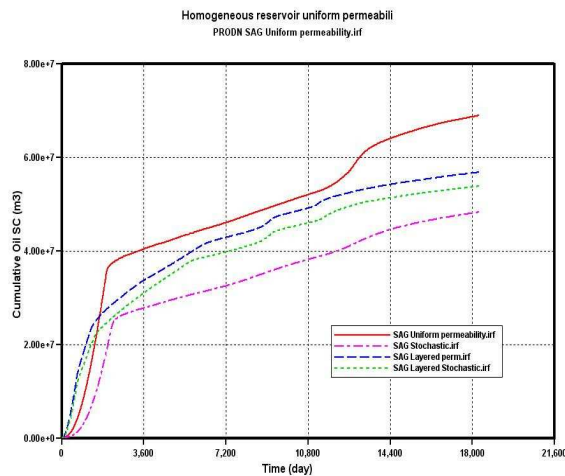


Figure E.5 Cumulative oil production for SAG processes following water flooding (higher oil viscosity). Homogeneous (red line), stochastic permeability (purple line), layered reservoir (blue line) and layered stochastic (green line)

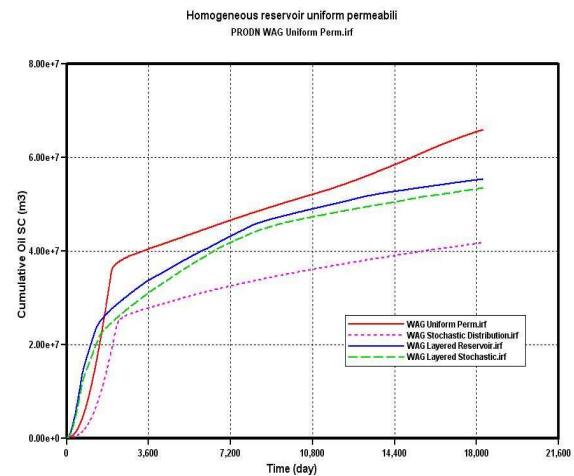


Figure E.6 Cumulative oil production for WAG processes following water flooding (higher oil viscosity). Homogeneous (red line), stochastic permeability (purple line), layered reservoir (blue line) and layered stochastic (green line)

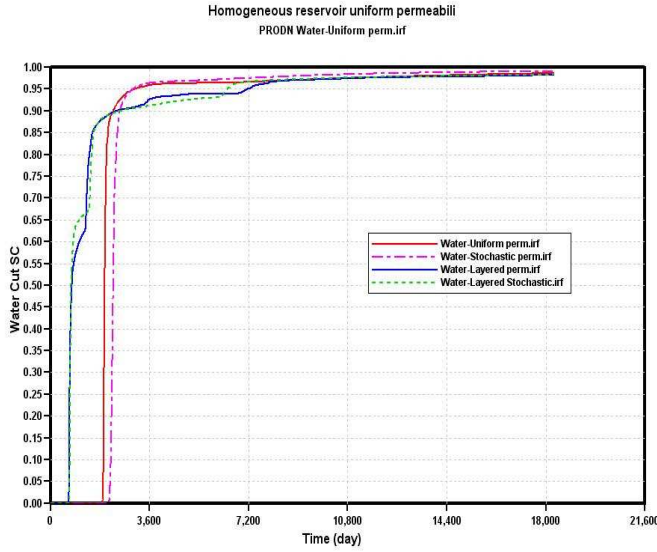


Figure E.7 Water cut water flooding (higher oil viscosity). Homogeneous (red line), stochastic permeability (purple line), layered reservoir (blue line) and layered stochastic (green line)

**Table E 1: Incremental recoveries for sensitivity analysis with respect to 40 years NFA**

Different Scenarios	Surfactant flooding -40 years	Gas flooding - 40 years	Foam co-injection -40 years	SAG processes -40 years	WAG processes -40 years	Remarks
Homogenous Reservoir 200mD	0.3%	-4.8%	9.4%	8.8%	7.1%	Negative value indicates that NFA recovery is higher than gas recovery
Stochastic Distribution 50- 350mD	5.7%	5.0%	7.3%	8.0%	2.5%	
Layered Reservoir 2000mD 200mD 1000mD 50mD	0.4%	-9.4%	4.5%	2.8%	1.6%	Negative value indicates that NFA recovery is higher than gas recovery
Layered stochastic Distribution 1400-2600mD 100-300mD 600-1400mD 20-80mD	0.7%	-8.2%	2.6%	2.7%	2.4%	Negative value indicates that NFA recovery is higher than gas recovery

**Table E 2: Total recovery factors for sensitivity analysis 50 years injection scenarios**

Different Scenarios	Water flooding & NFA - 50years	Surfactant flooding follow by water flooding-50 years	Gas flooding follow by water flooding-50 years	Foam co-injection follow by surfactant preflush follow by water flooding-50 years	SAG processes follow by water flooding-50 years	WAG processes follow by water flooding-40 years
Homogenous reservoir	48.2%	48.5%	43.4%	57.6%	57.0%	55.3%
Stochastic distribution	32.6%	38.3%	37.6%	39.9%	40.6%	35.1%
Layered reservoir	44.9%	45.3%	35.5%	49.4%	47.7%	46.5%
Layered stochastic distribution	42.5%	43.2%	34.3%	45.1%	45.2%	44.9%