DISSERTATION REPORT – FYP II

AHMED FATAH ALRAHMAN (14118)

Simulation Study of Polymer Flooding in Naturally Fractures Reservoirs

By

Ahmed Fatah Alrahman Ahmed Mohammed (14118)

Dissertation Report

Bachelor of Engineering (Hons)

(Petroleum Engineering) - September 2012

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UNIVERSITI
TEKNOLOGI
PETRONAS

CERTIFICATION OF APPROVAL

Simulation Study of Polymer Flooding in Naturally Fractures Reservoirs

By

Ahmed Fatah Alrahman Ahmed Mohammed

A Project Dissertation Submitted To The

Petroleum Engineering Program

Universiti Teknologi PETRONAS

In Partial Fulfillment of the Requirement For The

BACHELOR OF ENGINEERING (Hons)
(PETROLEUM ENGINEERING)

Approved by,

____

(Mr. Ali F. Mangi Altae'e)

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK

September 2012

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

AHMED FATAH ALRAHMAN AHMED MOHAMMED

ABSTRACT

This project presents a comprehensive simulation study on Polymer-Surfactant injection in the Naturally Fractured Carbonate Reservoirs (NFR). Not too many simulation studies have been done on this area to investigate the performance of the chemical flooding in these kinds of reservoirs as they differ from the conventional ones by many characteristics, and about one fifth of the oil reserves in the world rely under the NFR. However, most of the studies that have been done are experimental studies made for a specific area or field, and it worth to mention that most of the results indicate the success of using Chemical Flooding in NFR, which make the Chemical Flooding Technique becomes more effective and efficient as well as challenging method nowadays.

Naturally Fractured Reservoirs are widely found at the Middle East and North Sea areas, and usually they are described by mixed to oil-wet reservoirs, low porosity and low matrix permeability and high fractured permeability. Oil recovery in this type of reservoir is usually done by increasing the spontaneous imbibition either by altering the wettability or lowering the interfacial tension (IFT).

To evaluate the performance of the Polymer-Surfactant flood in the NFR, a commercial simulator CMG STARS version 2011 is used to build the simulation model for this study, using the Dual-porosity Dual-permeability (DPDP) approach. Hence, different injection scenarios has been evaluated and compared with the results that obtained from the literature, to have better judgment on the results. A result of 60% recovery factor has been achieved when using Polymer-Surfactant flood, which is relatively higher than using Polymer of Surfactant alone. This is due to the mechanism of lowering the IFT and altering the wettability.

ACKNOWLEDGEMENTS

All the thanks firstly go to Allah who helped me completing this project in a proper way, and within the time, my thanks also go to my parents who helped me along my entire study life. And my deepest gratitude shall be given to my supervisor Mr. Ali Fikret Mangi who helps me in order to complete this project with his full support, guiding and sharing knowledge, working on this project have given me a very good experience of how to obtain knowledge and work as engineers work. Not to be forgotten all my friends and colleagues, and also Universiti Teknologi PETRONAS who provides the facilities to complete this work.

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ABBREVIATIONS AND NOMENCLATURES

EOR= Enhanced Oil Recovery.

NFR= Naturally Fractured Reservoirs.

OIIP= Oil Initially In Place.

IFT= Interfacial Tension.

DPDP= Dual-Porosity Dual-Permeability.

CMG= Computer Modeling Group software.

RF= Recovery Factor.

SPF= Surfactant-Polymer Flood.

CHAPTER 1:

INTRODUCTION

1.1 Project Background.

Nowadays, most of the reservoir engineers all over the world concern about increasing the oil recovery from the naturally fractured reservoirs, the common techniques that has been used are related to the Enhanced Oil Recovery (EOR) with different methods. One of the most effective techniques is the chemical flooding, by using Polymer, Surfactant and Alkali systems. This project studies the effect of Polymer-Surfactant flooding on the recovery of the oil in the Naturally Fractured Reservoirs (NFR).

A large quantity of world's oil reserves is found in the carbonate fractured reservoirs (Roehl and Choquette, 1985). And about 60% of the original oil in place (OIIP) which left without recovery has to be found in the carbonate NFR. And most of these carbonate NFR have an oil-wet or mixed-wet systems (Mohan, 2009).

NFR have different characteristics than the conventional reservoirs that they have low porosity and high permeability due to the fractures, however in this project a technical background about the nature of NFR will be reviewed, and also the basic principle of the chemical EOR, besides that, the mechanism of the chemical flooding process will be explained.

1.1.1 Naturally Fractured Reservoir (NFR).

NFR are considered as very important contributors to the world's oil reserves (Nelson, 1985), and approximately one fifth of the oil reserves has to be found in NFR (Firoozabadi, 2000). NFR are differs from the conventional reservoirs that they normally have lower porosity and higher permeability. Bourbiaux (2010) has discussed in detail the typical geological settings of the fractured reservoirs by providing the well-known examples of NFRs worldwide. Later on when the modeling of the NFR is constructed, the dual porosity and dual permeability will be used to build the model.

The presence of porous blocks is the common basic element in all NFRs, it's called the matrix, and of a connected network of fractures. This common element has been expressed in all the dual-porosity dual permeability models in the literature. Using the dual-porosity dual permeability approach had been pointed by Barenblatt et al. (1960) and Root (1963), in order to simulate the flow behavior and to model the transient well test responses of NFR.

Generally, NFRs can be classified into four categories (Allan and Qing Sun, 2003):

i. NFRs in which fractures act as storage capacity and flow pathways;
ii. NFRs in which matrix provides some storage capacity and fractures are the flow pathways;
iii. NFRs in which matrices are storage capacity and fracture act as flow conduits;
iv. NFRs in which matrices act as storage capacity and flow pathways.

In this project the NFR is considered to be a light carbonate oil reservoir having both matrix and fracture Permeability (explained more in the methodology part).

1.1.2 Chemical EOR.

Chemical EOR is becoming more important with the current economic aspects especially for the water flooding (Nawaf, 2011). Chemical EOR techniques include Alkali, Polymer or Surfactant flooding, or a combination of these chemicals. However, these (Alkali, Polymer and Surfactant) techniques are one of many ways to recover the oil from the NFR (Manrique, et al. 2006).

Surfactants are used to lower the interfacial tension IFT between the oil and water, while the Alkali is used to increase the PH to lower the surfactant adsorption. Polymers are used to increase and improve the sweep efficiency and lower the mobility ratio (Mohan, 2009). ASP techniques has been used and developed for the carbonate reservoirs in the last 10 years (Jiecheng, et al. 2008).

1.1.3 Mechanism of the Chemical EOR in NFR.

In order to better understanding the mechanisms of oil recovery in NFR by chemical flooding, the derive forces that causes the flow of the oil should be identified. When the initially oil-wet matrix are surrounded by water, the hydrostatic and buoyancy forces causes upward movements for the oil, but in the other direction the gravitational and capillary forces appear to force the oil to remain the small pores and stuck with the rock, the capillary forces described normally as negative force (Jamaloei, 2011).

However, the IFT between the oil and rock will be high, so when we inject the chemical solution with the water, it will reduce the IFT between the injected fluid and the hydrocarbon, which will reduce the capillary forces and the oil will start to flow as it will be displaced by the injected fluid.

1.2 Problem Statement.

As stated earlier in this project, about 40-60% of the OIIP in reservoir that left without recovery are found to exist in the fractured carbonate reservoirs (Nawaf, 2011). There is no yet a conventional method or technique to be used in order to recover the oil from the NFR, that due to the nature of the NFR which differs from the common reservoirs by many characteristics. That which makes it a very challenging for the reservoir engineers to recover the oil from the NFR, which somehow razes the problem that the reservoir engineers are facing in order to deal with this type of reservoir.

1.3 Objectives.

This project will present a comprehensive simulation study about the impact of the chemical flooding in the Naturally Fractured Carbonate Reservoirs, in order to improve the oil recovery. So the objectives of this project are to:

i. Evaluate the performance of the Polymer injection in NFR. "Polymer will be used as the main chemical solution".
ii. Construct different model scenarios of injecting a combination of (Polymer, Surfactant and Alkali) by Lowering the IFT and using wettability modifier.

1.4 Feasibility of the Study.

This project requires very advanced simulation software in order to conduct the study, by using CMG STARS version 2011 software –which is available at UTP-, this project can be achieved within the proposed time, and if an experimental study is required to be done, the EOR facilities are fully prepared for such study.

CHAPTER 2:

LITERATURE REVIEW

2.1 General Review.

Naturally fractured reservoirs are usually expressed by mixed wettability and low matrix permeability which leads to low hydrocarbon recovery and high residual oil saturation. Not too many projects have been done in order to evaluate the performance of chemical flooding in NFR.

There is one simulation study has been done by Nawaf, (2011). He has performed a simulation study on Surfactant-Polymer Performance (SPF) in Fractured Carbonate Reservoirs, and however, the (SPF) enhances the recovery by increasing the spontaneous imbibition either by altering the wettability or by lowering the interfacial tension. **Figure (1)** below shows the spontaneous imbibition through the buoyancy forces (Hirasaki and Zhang, 2004).

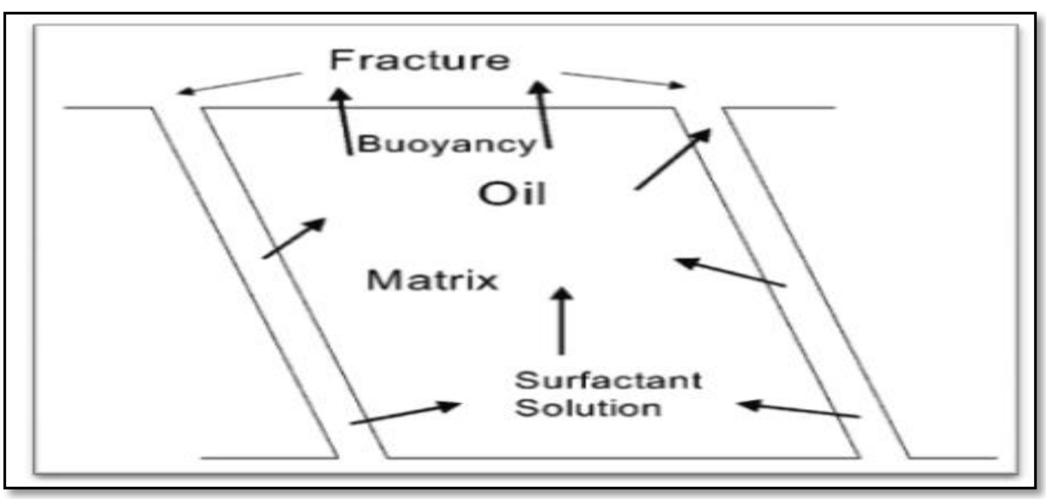


Figure (1)

Evaluating the (SPF) has been simulated by using CMG STAR software, by designing a dual-porosity dual-permeability (DPDP) simulation model. Interfacial tension plays an important role in order to reduce the residual oil saturation.

It was found that in order for the water flood to have effect on residual oil saturation (S_{or}) reduction, the IFT should be lowered by a factor of minimum 1,000 (Taber, 1969).

Another study on Chemical Flooding of Fractures Carbonate Reservoir Using Wettability Modifier has been completed by Nariman, et al. (2008). The main key in their study was to alter the wettability from oil-wet towards water-wet, which will be resulted in expelling more oil from the matrix to the fractures. Besides that, wettability alteration has been proved as an effective way to enhance the spontaneous imbibition in oil-wet NFR (Austed and Milter, 1997).

As this project will be focusing more on the Polymer flooding by increasing the Spontaneous Imbibitions , it has been reported from the literatures that some studies has concern about the same issue;

Chen et al. (2000) used nonionic surfactant for enhancing the spontaneous imbibitions. Also Spinler et al. (2000) have evaluated 46 different types of surfactants, and came out with different results and conclusions.

Here also listed some of the literatures as it has been reported;

i. Alkali-surfactant-polymer flooding (Daoshan et al., 2004);
ii. Surfactant-polymer flooding also known as low-tensionpolymer flooding (YadaliJamaloei et al., 2011b);
iii. Alkali-surfactant flooding (Liu et al., 2006);
iv. Dilute surfactant flooding (Krumrine, 1982).

2.2 Literature Analysis.

Most of the reported studies from the literature indicate that using chemical flooding in NFR is a challenging method; however, if it is applied successfully it will lead to recover more oil from the fractured reservoirs. In this project, Polymer-Surfactant flooding in carbonate fractured reservoirs will be tested and simulated to animate the flow behavior in the reservoir.

On the other hand, not too many simulation studies has been done in this area of study, this project as stated earlier will conduct a simulation study by constructing a 3D model with varieties of scenarios to evaluate the optimum method that result in maximum oil recovery.

However, challenges will be faced during the simulation study such as the reservoir temperature, the possibility of chemical losses and Polymer Adsorption and retention, these points will be discussed in the next levels while conducting the study.

CHAPTER 3:

METHODOLOGY

3.1 Research Methodology:

Simulation of chemical flooding in NFR has been reported to be modeled by using Dual-porosity Dual-permeability (DPDP) approach (Warren and Root, 1963). This method has some limitation but it is still the best way to represent the NFR (Tarahhom et al., 2009).

In this project, the DPDP approach will be used as it has been used by Nawaf, (2011) in his simulation study on Surfactant-Polymer injection in NFR. However, in this project a similar approach that has been used in the literature is proposed to be used (Nawaf, 2011).

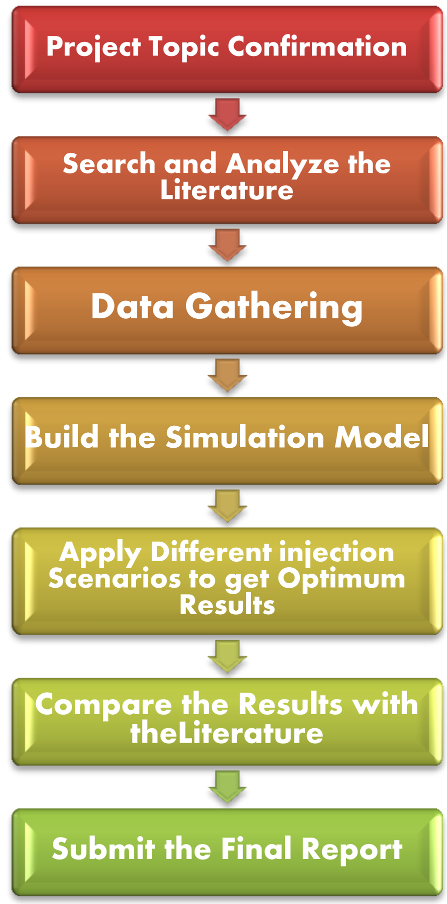
A hypothetically NFR model will be constructed by using CMG STARS version 2011, to simulate the chemical flooding in NFR. Here are some assumptions that will be applied on the study;

i. The reservoir is considered as light oil reservoir (black oil model).
ii. Using DPDP model to capture the effect of the fractures in the field.
iii. Rock and Fluid properties will be taken from a published data for a common carbonate fractured reservoir including capillary pressure and wettability conditions.
iv. Assuming the polymer has both effect on reduction on IFT and altering the Wettability, in addition to increase the injected fluid viscosity.

3.2 Research Procedure:

Here is the procedure that will be followed in order to conduct this study:

i. Project Topic Confirmation;
ii. Search and Analyze the Literature;
iii. Data Gathering;
iv. Build the Simulation Model;
v. Apply Different Injection Scenarios to Get the Optimum Results;
vi. Compare the Results with the Literature;
vii. Submission of Final Report.



3.3 Project Activities.

The main activity of this project is to build a good simulation model that can give clear descriptions of the flooding process; otherwise faulty estimation of field performance may occur.

3.4 Key Milestone.

No	Activities	Date
1	*Submission of Progress Report*	*7 Nov. 2012 (Wk7)*
2	*Pre SEDEX*	*(Wk10-11)*
3	*Submission of Final Report*	*(Wk12)*
4	*VIVA*	*(Wk14)*

Table (1)

3.5 Gantt Chart.

No	Detail/Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	*Topic Selection / Proposal*	■	■												
2	*Preliminary Research Work*		■	■	■	■	■								
3	*Submission of Proposal Defense Report*							●							
4	*Proposal Defense (Oral Presentation)*								■	■					
5	*Project Work Continues*										■	■	■		
6	*Submission of Interim Draft Report*												●		
7	*Submission of Interim Report*													●	

Table (2)

3.6 Tools.

This simulation study will be conducted using a commercial simulator, CMG STARS, 2011, which is available at UTP. No other tools are required to conduct this study.

3.7 Simulation Model.

The simulation model of NFR is modeled using dual porosity- dual permeability approach, as it has been proved to be the best way of representing the NFR. The reduction of IFT is assumed to be achieved as an effect of the polymers as well as the alteration of the wettability of the reservoir. Figure 2 shows the DPDP fluid communication.

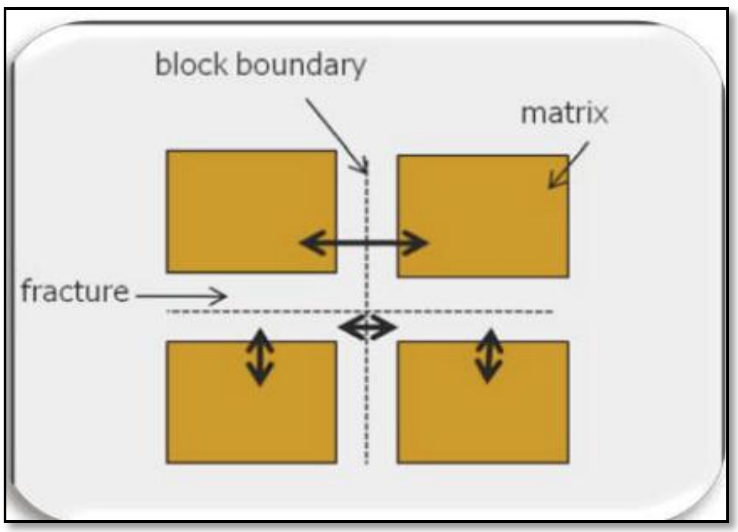


Figure 2

3.7.1 Simulation Approach.

To achieve the research objectives a hypothetical naturally fractured reservoir has been built. A commercial simulator CMG STARS version 2011 has been used to utilize the study, as it has the capability to simulate the chemical EOR process. The research involves the following steps:

i. Collect the required data from the literature; PVT, Production and Rock & Fluid properties data has been identified; in addition of the chemical properties base on the screening criteria. Tables 3 and 4 below show the simulation data that are used.

Fluid Properties used in simulation				
Property	**Water**	**Polymer**	**Surfactant**	**Oil**
Viscosity (cp)	0.6	70	0.6	3.2
Concentration %	0.91	0.00075	0.09	0.00
Phase	Aqueous	Aqueous	Aqueous	Oleic

Table (3)

Simulation Data			
Injector-Producer Distance	950 ft	**Matrix Perm.**	50 md
Reservoir Depth	10500 ft	**Matrix Porosity**	0.2
Reservoir Pressure	4850 psi	**Fracture Perm.**	1000 md
Initial oil saturation	0.81	**Fracture Porosity**	0.01
Connate water saturation	0.2	**Fracture Spacing**	10 ft

Table (4)

ii. Build the simulation model with a grid size 81 x 31 x 2, using DPDP approach, and 5-spot flood pattern, as shown in the Figure 3 below.

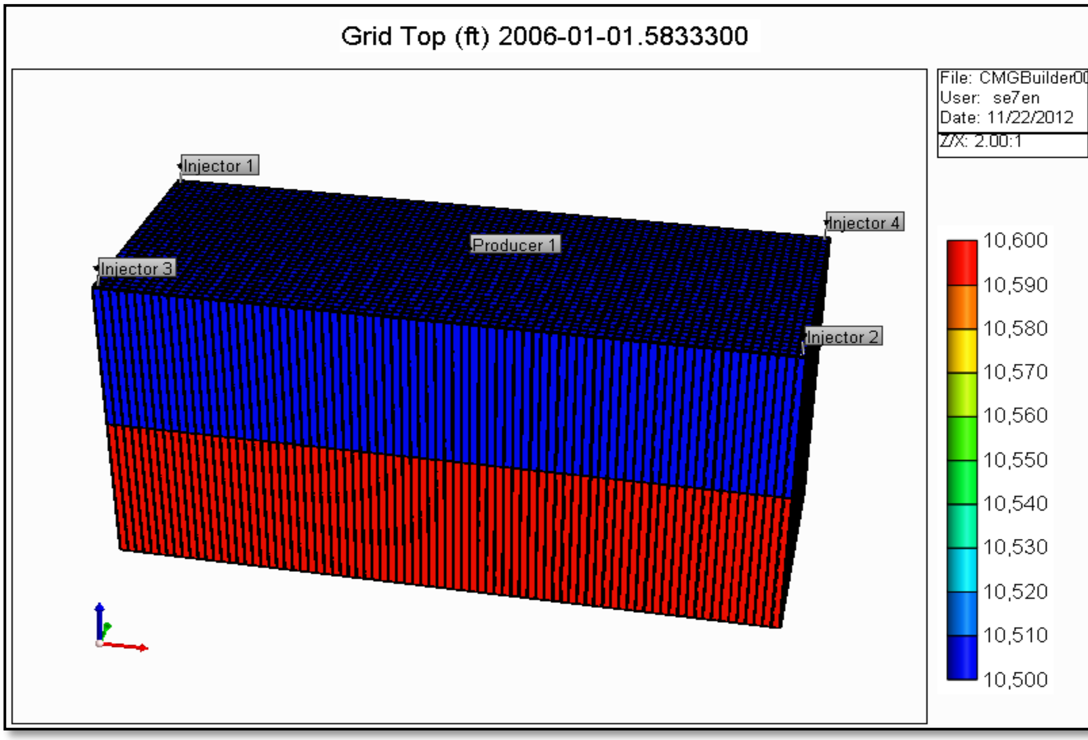


Figure 3

iii. Three different scenarios has been evaluated;

  i. Inject Polymer-Surfactant together.
  ii. Inject Polymer only.
  iii. Inject Surfactant only.

iv. After running the simulation, the results were analyzed and compared with the results from the literature.

3.7.2 Simulation Process and Methodology.

- Firstly, the model should be build using CMG Builder, to represent the reservoir and the fluid model together, for this part the following procedure has been followed;

1) At the beginning, the Simulator type, units' format and reservoir type should be chosen as shown in the print screen image below, and then the pattern of the reservoir is chosen as a normal 5 spot pattern.

2) The reservoir size is 81 x 31 x 2 in dimension. Which gives 5022 grid block, both matrix and fractured, it should be mentioning that the DPDP approach is used to model the reservoir.

3) Building the fluid model: Create components and specify phases in which each component can appear; Specify:

   - Pure component properties
   - Gas-liquid and liquid-liquid K values
   - Liquid and solid phase densities
   - Liquid and gas phase viscosities
   - Reference and surface pressure and temperature conditions
   - Component/phase distribution for well production reporting

- Then the fluid model data generated and Import fluid model data generated from Black Oil PVT data.

4) For the relative permeability curves, the correlations have been used to generate the curve, however the 3-phase relative permeability has been generated also.

5) The black oil PVT import wizard can be started from the top menu item Components → Import Black Oil PVT… This wizard will create a completely new fluid model for STARS, using carefully calculated parameters that are matched to the black oil PVT data. Since STARS uses K value and component based formulations for the fluid model, it is strongly recommended to use this wizard anytime major parameters are to be changed in the fluid model. Changing parameters manually in the data set without the help of this wizard will have un-predictable results, and will usually result in a fluid model that no longer matches the black oil PVT data.

6) The Initial Conditions section allows entering information regarding the state of the reservoir at initial time. Additional information that can be entered in this section includes capillary-gravity method of calculating vertical equilibrium, initial reservoir saturations, reference depth and pressure and three phase contact depths.

7) For the numerical section the following data are set and insert to make the numerical analysis for the model;

   - First Time Step Size after Well Change (DTWELL) ; 0.001
   - Isothermal Option (ISOTHERMAL) ; ON

- Model Modulation (TFORM) ; ZT
- Convergence Tolerance (CONVERGE) ; Total Residual
- Maximum Average Scaled Residual for all Equations ; TIGHT

8) Grid Design:

Symmetry elements are used frequently in Chemical simulation for a number of reasons:

1. Compared with black-oil models, thermal models require much more CPU and storage per grid block. Therefore, less blocks can be used for a given computer storage limit.

2. Chemical EOR processes require more grid blocks per well or per pattern, since fronts are sharp and distinct.

3. Accuracy can be maximized for use in test and sensitivity runs.

4. Some results from one element may be generalized to other elements and patterns.

5. Pattern interference can be investigated by sensitivity runs with different injection share or production share.

Figure below shows how a symmetry element may be picked from a pattern. Each of the grids is attempts to model the pattern element contained within the dotted line.

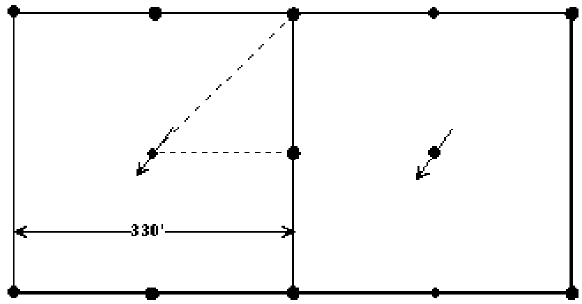


Figure E.8a: Two 2.5 acre inverted nine-spot patterns

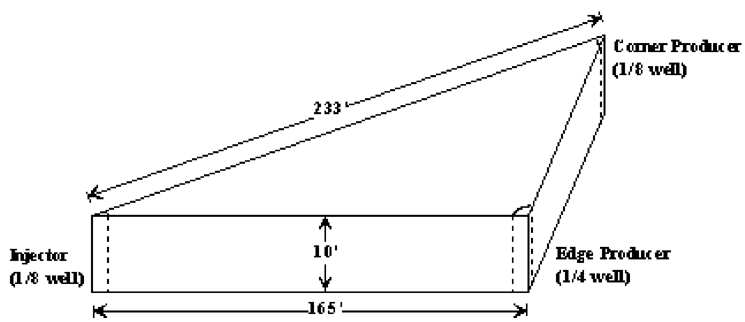


Figure E.8b: Basic reservoir one eighth of 2.5 acre nine-spot pattern, 10 ft. pay

9) Add the chemicals model into the fluid model, in this case both Polymer and Surfactants are considered, the below screen sheet shows the values that used for the polymer and surfactant concentration.

10) After defining all the components, the wells has to be identified, basically in this case there are four injection wells and one producer, however, to maintain the pressure in the reservoir and to have many results for our model, many cases has been studied and applied as the following;

i. First case: Water flooding followed by Polymer-Surfactant flood, then water chase followed by polymer chase, and lastly water flooding until the end of simulation time.

ii. Second case: water flooding followed by Only Surfactant flood, the water chase, then polymer-surfactant flood, and lastly water flood until the end of simulation time.

11) Injection Scenarios:

The next step is to add the dates (time period) for each flooding type as mentioned above, however to cut the simulation time the duration is represented in months and the time step in hours.

Normally in any experimental study of core flooding the chemical flooding period is shorter due to the cost involves with respect to oil prices. Therefore, to have a close scenario of the field practices, a duration of two years is proposed consisting of the following;

- Six months of water injection.
- Six months of chemical injection.
- One year of water flood until the end of the simulation time.

12) By that the model has been created and it's ready to be run using CMG STARS simulator.

13) Below are the print screen images for the steps.

3.8 Simulation Outputs.

- The rock and fluid properties that are modeled by the simulator are shown in the following graphs;

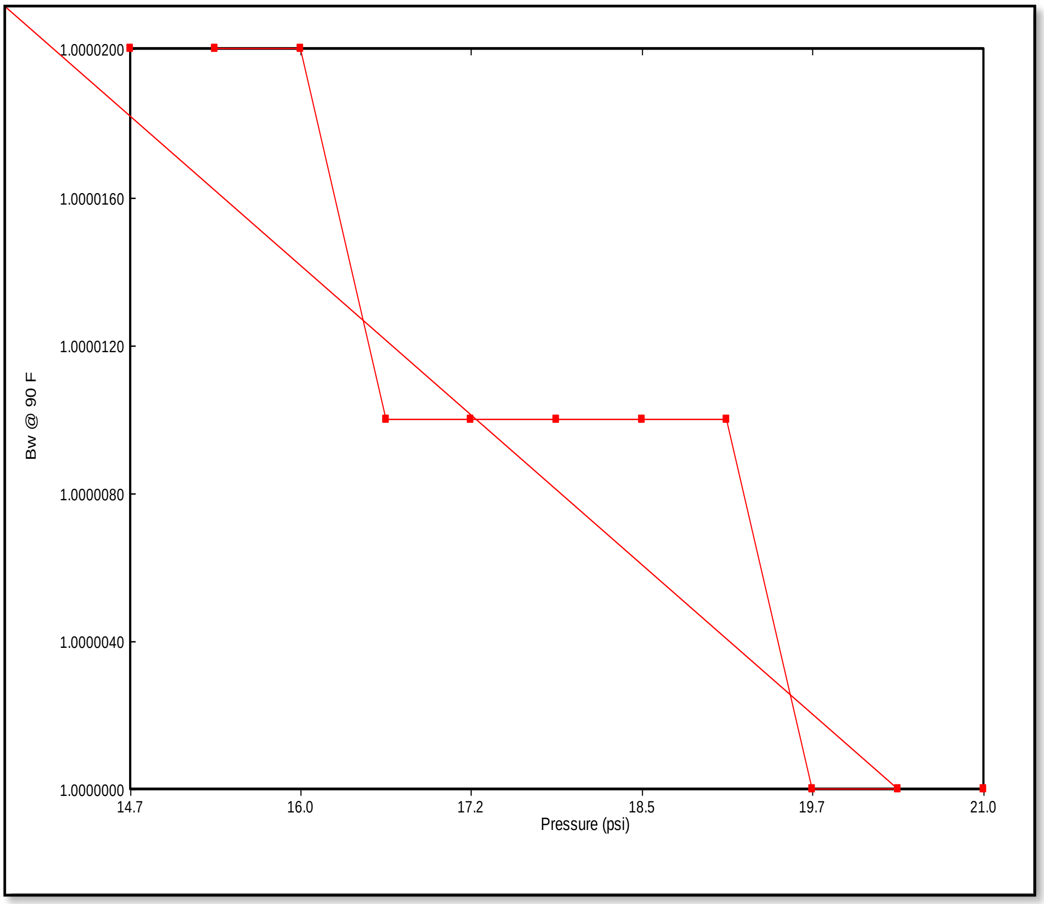


Figure 4

Figure (4) represents the water formation volume factor vs. the pressure, it can be realized that the amount of B_w is decreasing with increasing in surface pressure, however the change is not that much which will not affect the results later on.

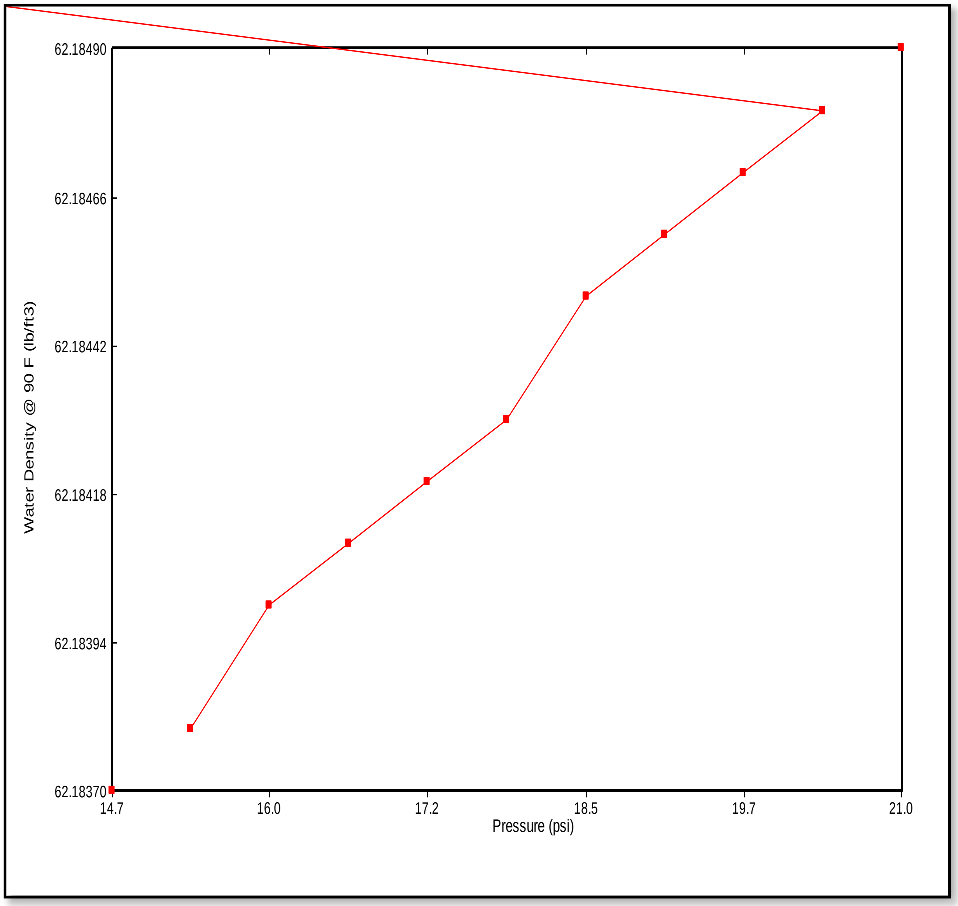


Figure 5

In Figure 5 the water density is shown, as it is increasing with the increasing of the surface pressure.

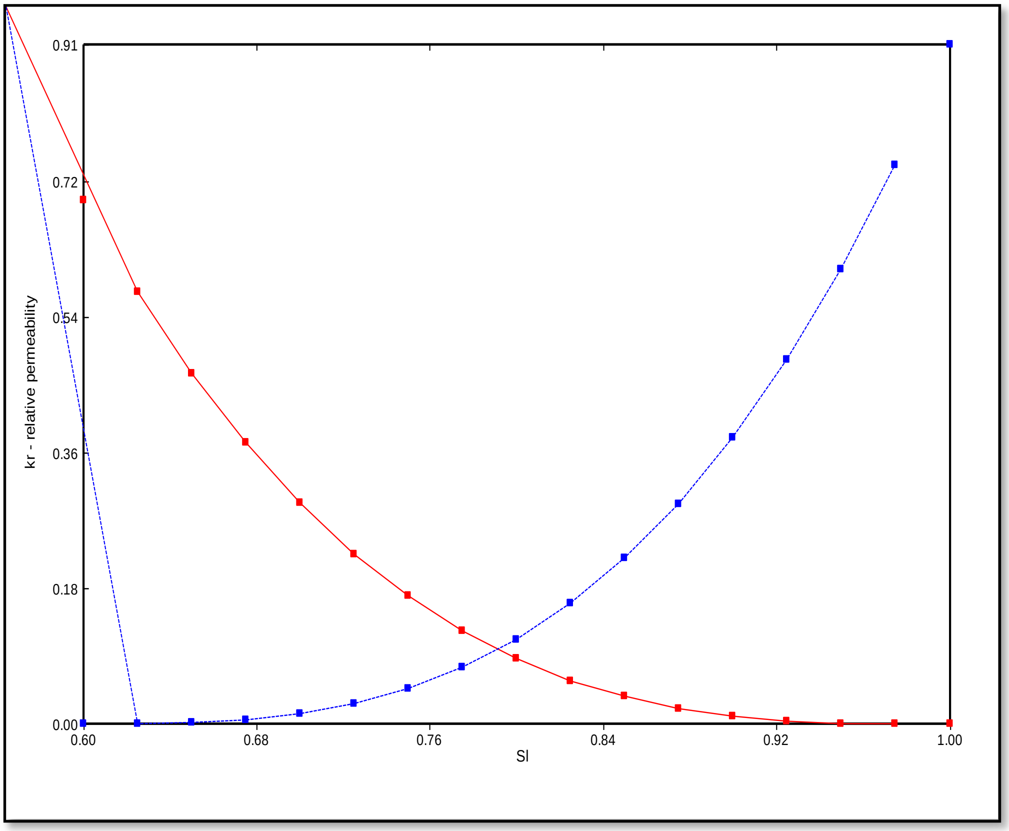


Figure 6

Figure 6 shows the relative permeability curves for oil and water permeability for the system.

Figure 7 below is a triangle representation of the 3-phase relative permeability for the system, no gas has been considered to be produced when the Polymer is injected to the reservoir.

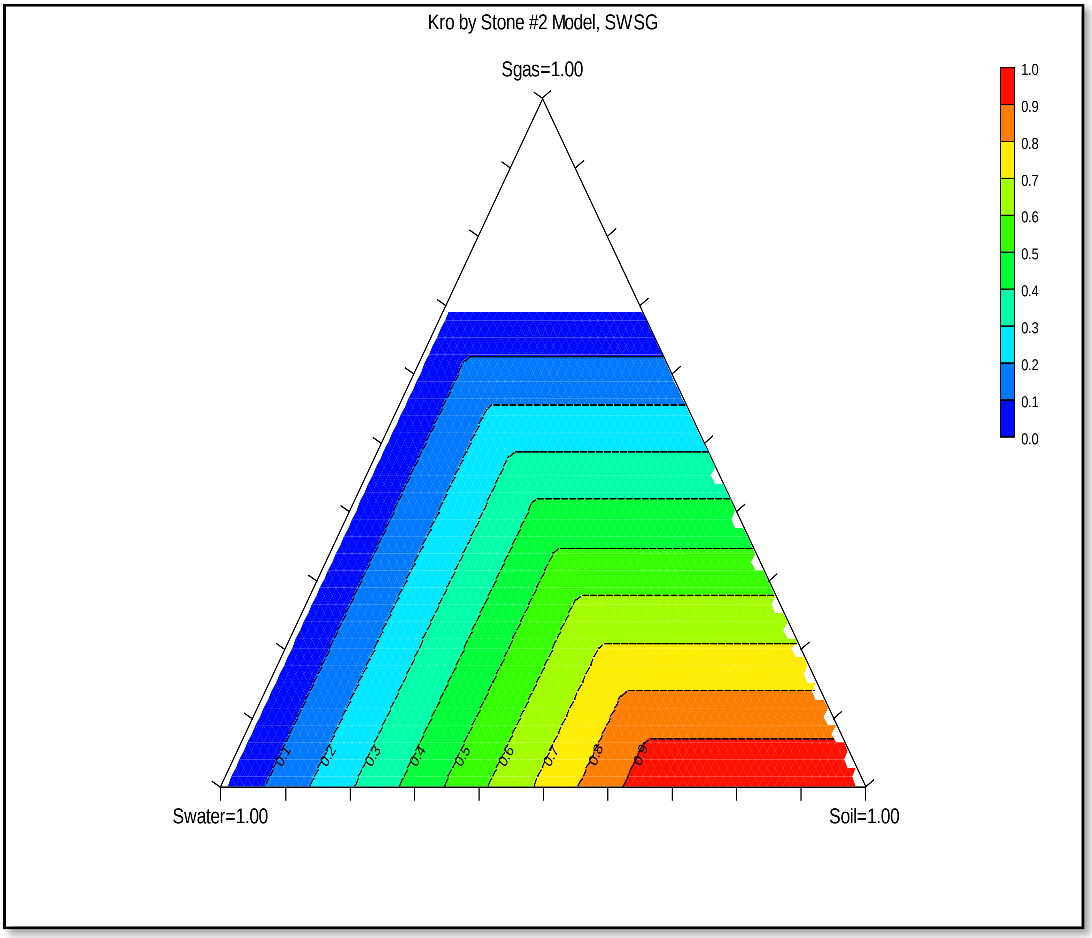


Figure 7

3.9 Screening Criteria.

- Polymer flooding is the injection of a slug that contains water, surfactant, polymer, electrolyte (salt), sometimes a co-solvent (alcohol) and possibly a hydrocarbon. The size of the slug is often 5-15% PV for high surfactant concentration and 15-50% PV for low concentration followed by polymerthickened water. The polymer concentration often ranges from 500-2000 mg/L and the volume of polymer solution injected maybe 50% PV or more.

- ASP flooding is quite similar except that much of the surfactant is replaced by low-cost alkali so larger slugs can be generated at lower cost and the polymer is usually incorporated in the larger, dilute slug.

- The mechanisms are:
  - Lowering the interfacial tension between the oil and water.
  - Emulsification of oil and water, especially in the alkaline methods.
  - Wettability alteration (in the alkaline methods).
  - Mobility enhancement.

- Figure 8 shows the screening criteria for the Polymer and the Surfactant flooding. These criteria are based on the filed projects that have been conducted successfully.

- The criteria are related to the oil viscosity as a main factor, as it's in direct proportion with the mobility ratio. However, other factors such as the permeability of the reservoir and the depth may be considered in choosing the type of injecting fluid.

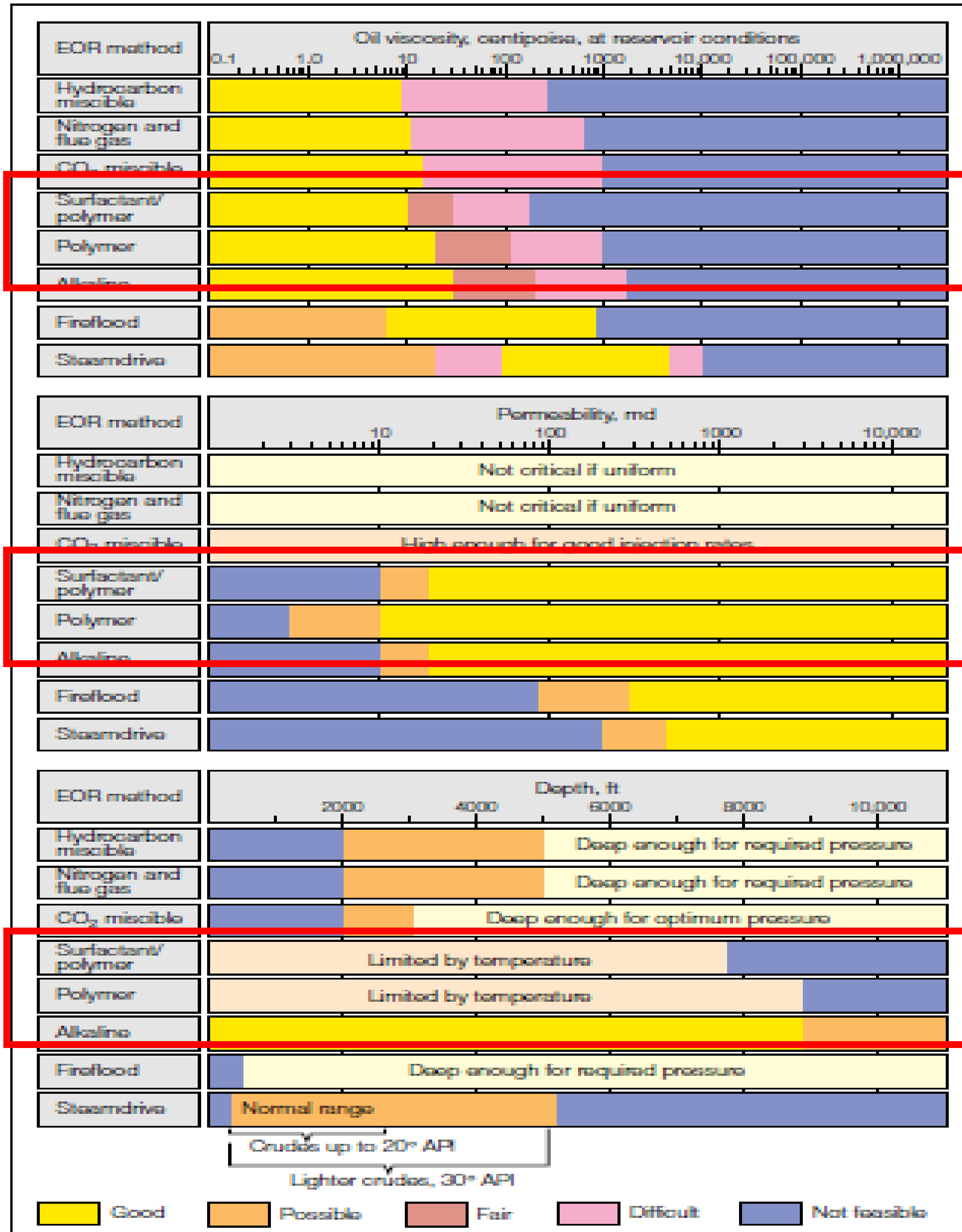

EOR method
Oil viscosity, centipoise, at reservoir conditions
0.1
1.0
10
100
1000
10,000
100,000
1,000,000
Hydrocarbon miscible
Nitrogen and flue gas
Surfactant/ polymer
Polymer
Fireflood
Steamdrive
EOR method
Permeability, md
10
100
1000
10,000
Hydrocarbon miscible
Not critical if uniform
Nitrogen and flue gas
Not critical if uniform
Surfactant/ polymer
Polymer
Fireflood
Steamdrive
EOR method
Depth, ft
2000
4000
6000
8000
10,000
Hydrocarbon miscible
Deep enough for required pressure
Nitrogen and flue gas
Deep enough for required pressure
CO_2 miscible
Deep enough for optimum pressure
Surfactant/ polymer
Limited by temperature
Polymer
Limited by temperature
Alkaline
Fireflood
Deep enough for required pressure
Steamdrive
Normal range
Crudes up to 20° API
Lighter crudes, 30° API
Good
Possible
Fair
Difficult
Not feasible

Figure 8

CHAPTER 4:

RESULTS AND DISCUSSION

The main results that are obtained and calculated from the software outputs are the recovery factors. In this study two types of results have been analyzed and discussed; the theoretical results and the results taken from the simulation. The reason of that is to compare the results with each other, and relate it to the results that given from the literature.

4.1 Theoretical Results.

- To conduct the theoretical part of the study, the simple frontal advance theory is applied to predict the recovery factor for the three different scenarios. However, some of the values are assumed in order to simplify the results.

- Table 5 shows the data that has been used for the calculation.

Data From Simulation	
Np= PV(Sorw-Sorc)Evw/Bo	
Number of blocks	5022
Pore Volume (PV)	1788913
Initial Water Saturation (Swi)	0.25
Formation Volume Factor (Bo)	1.25
ROS after water flood (Sorw)	0.45
ROS after chemical flood (Sorc)	0.08
Vertical Sweep Efficiency (Evw)	0.7

Table 5

- Here are the basic equations that used for the calculations part.

4.1.1 Equations used.

<u>The conservation equation:</u>

- A conservation equation is constructed for each component of a set of identifiable chemical components that completely describe all the fluids of interest.
- All conservation equations are based on a region of interest (with volume V) in which

	rate of change of accumulation
=	net rate of inflow from adjacent regions
+	net rate of addition from sources and sinks

- Each of these three terms will be considered separately, below.

<u>Accumulation Terms</u>

- The total gross volume of a grid block may be composed of the following:
  - Solid (inert) rock matrix (r)
  - Solid and adsorbed component (s)
  - Water or aqueous phase (w)
  - Oil or oleic phase (o)
  - Gaseous phase (g)

Thus the total volume is

$$V = Vr + Vs + Vw + Vo + Vg$$

The fluid volume is defined as:

$$Vf = Vw + Vo + Vg$$

and the void volume is defined as:

$$Vv = V - Vr = Vf + Vs$$

Void porosity is defined as:

$$\varphi v = Vv / V$$

Fluid porosity is defined as

$$\varphi f = Vf / V = (Vv - Vs)/V = (Vv/V) \bullet (1 - Vs/Vv)$$

4.1.2 Theoretical Calculations.

- After applying the equations, the below graphs has been produced and they show the performance of the flooding.

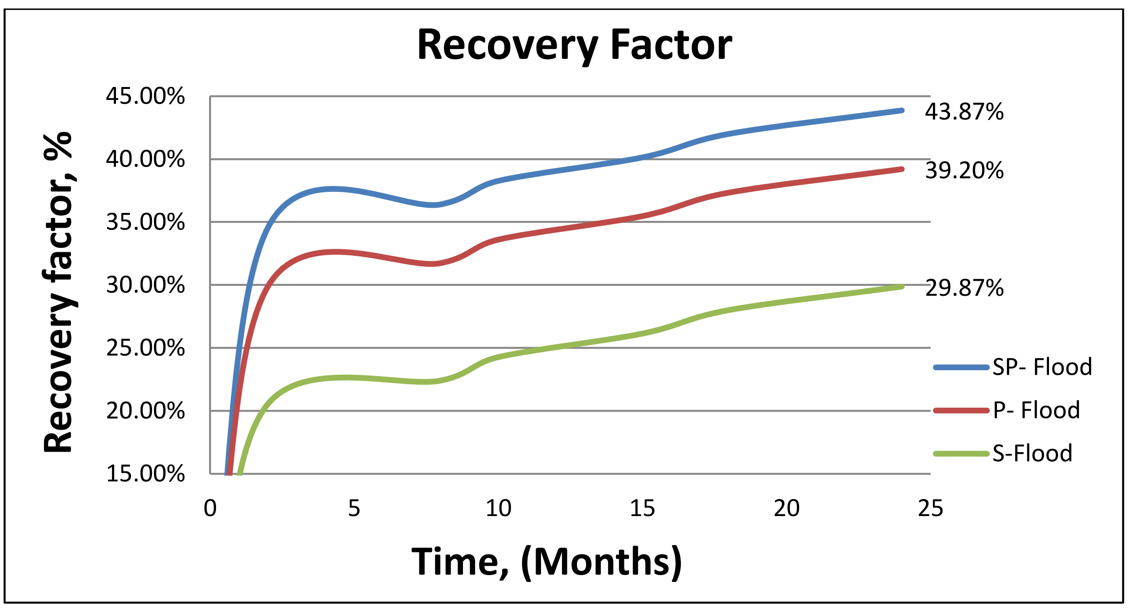
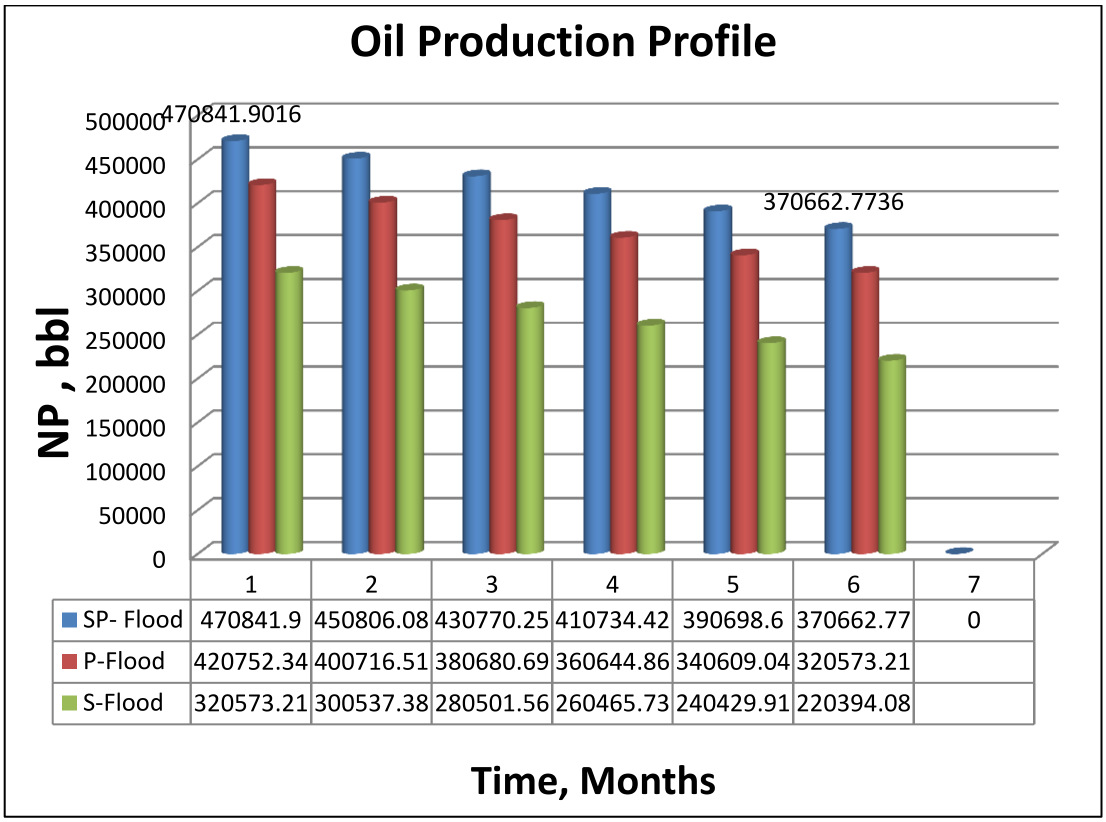


Figure 9

- Figure 9 is showing the recovery factors for the three injection scenarios. It can be realized that, the injection of both Polymer and Surfactant slug together gives the highest recovery factor for around 44%, followed by the injection of Polymer with recovery factor of 40%, and the Surfactant flood gives around 30%.



	1	2	3	4	5	6	7
SP- Flood	470841.9	450806.08	430770.25	410734.42	390698.6	370662.77	0
P-Flood	420752.34	400716.51	380680.69	360644.86	340609.04	320573.21	
S-Flood	320573.21	300537.38	280501.56	260465.73	240429.91	220394.08	

Figure 10

- Figure 10 is representing the oil production throughout the duration of the simulation study, it can be realized that the oil production is decreasing as the time goes. In this part of calculations, the water flood is not included, and that's the reason of having higher oil production at the early stages of the chemical flood process.
- On the other hand, the SP flood is relatively giving the highest oil production, which means it performs better that injecting Polymer of Surfactant alone.

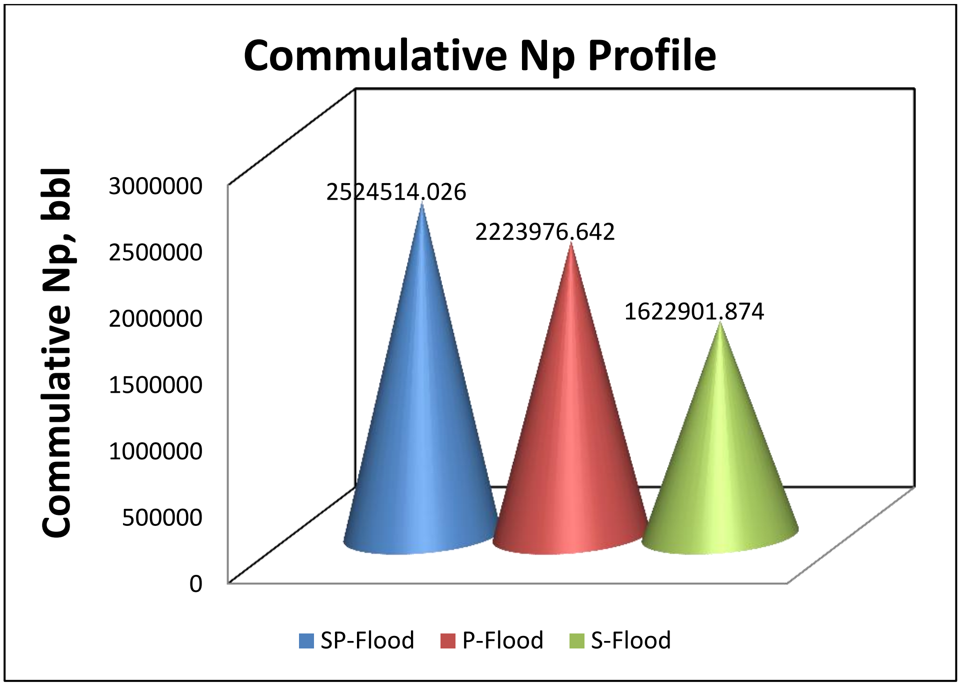


Figure 11

- Figure 11 shows the expected cumulative oil produced throughout the simulation period. It has to be found that the SP flood gives the highest oil production, followed by Polymer then Surfactant.

4.2 Simulation Results.

- For this part, the data used to calculate the recovery factor are taken from the simulation outputs. The total oil production is calculated based on the daily oil production, and then the recovery factor has been evaluated for each injection scenario.

- Figure 12 shows that the RF for the SP flood is the highest with 60%, followed by the Polymer flood with 55%, and the Surfactant indicates around 50%. This indicates the success of using Polymer-Surfactant flood in the NFR.

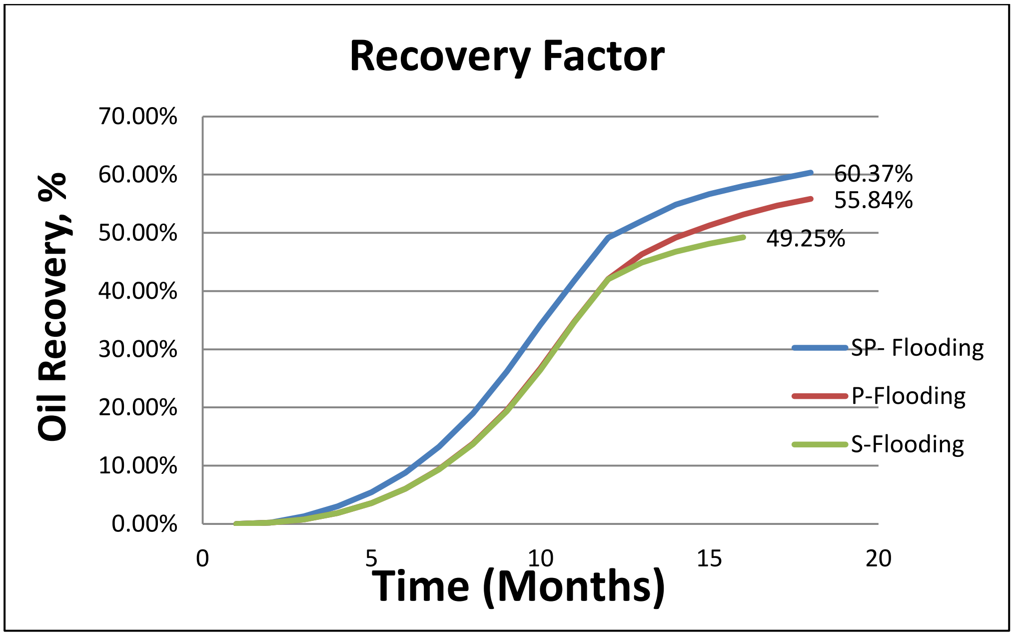


Figure 12

- It can be realized that the same trend for the Recovery Factor in the simulation results is achieved in the theoretical part, which means the simulation results is quite reliable.

- Base on the findings in figure 13, the oil production is plotted and it can be realized that, for the SP flood, the oil production is increasing simultaneously until it reaches the maximum at the 10^{th} month, then declining until the end of the simulation study. That indicates the effect of the water flood at the beginning then followed by the SP slug. For the Polymer and Surfactant flooding, it's obvious that the Polymer gives more oil production than the Surfactant, hence the water breakthrough earlier in the Surfactants due to the high effect of channeling and fingering.

- The cumulative oil production also has been evaluated, and it can be seen in figure 14.

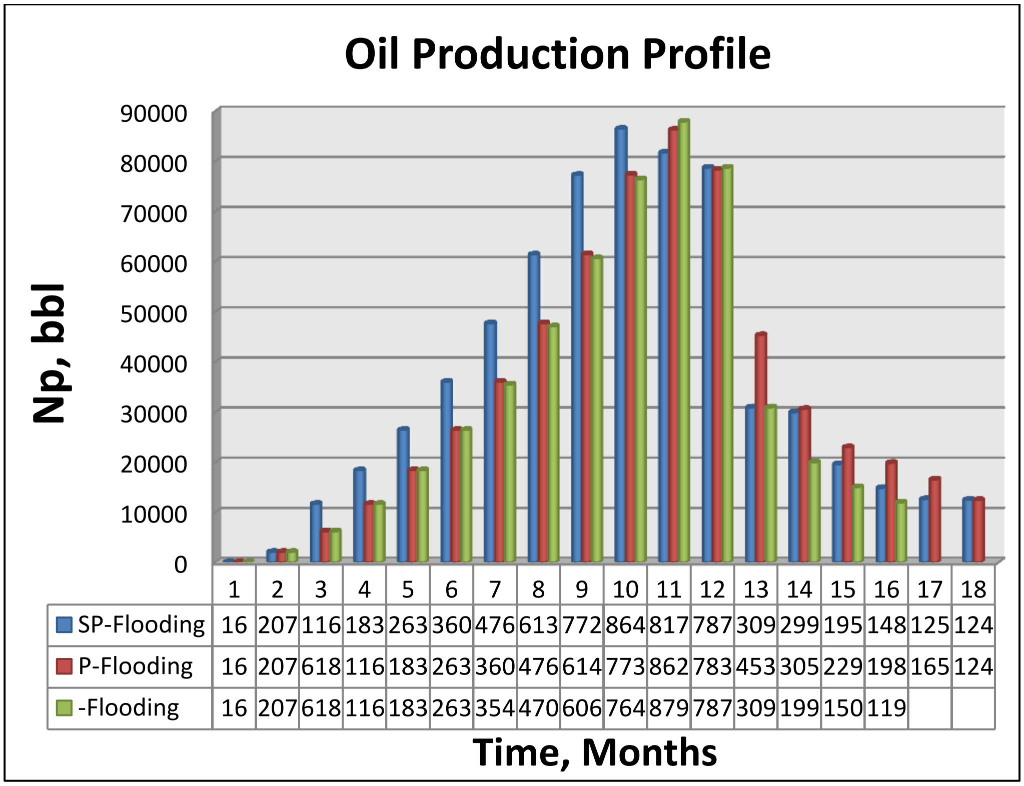


Figure 13

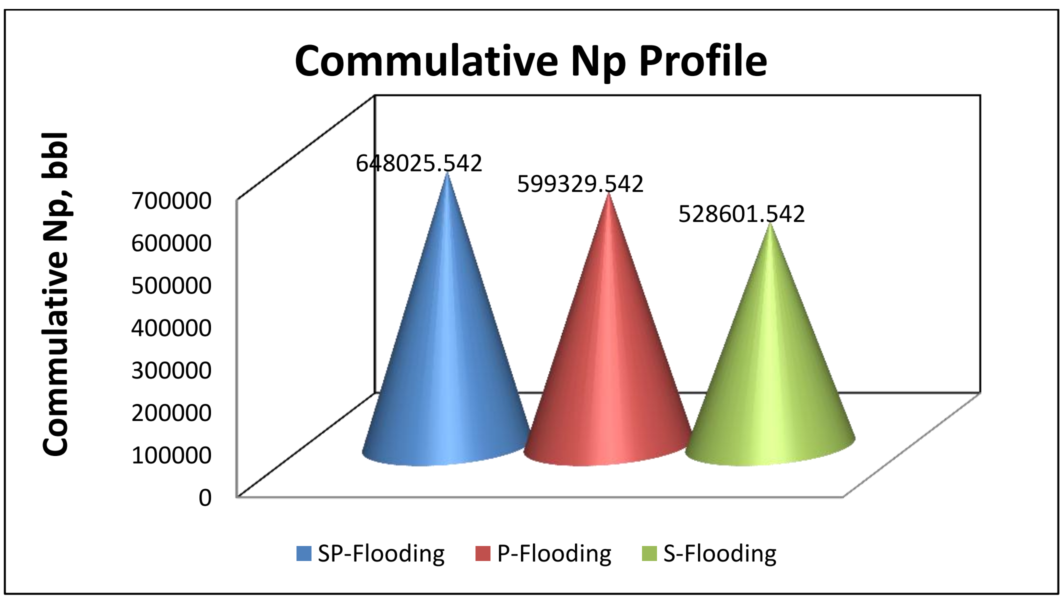


Figure 14

- The water cut profile has been plotted also to evaluate when the economical time to stop producing is. However, it is worth to mention that, the simulation study made to be stopped when the water cut reaches 90%. Figure 15 shows the water cut profile for the three injection scenarios.

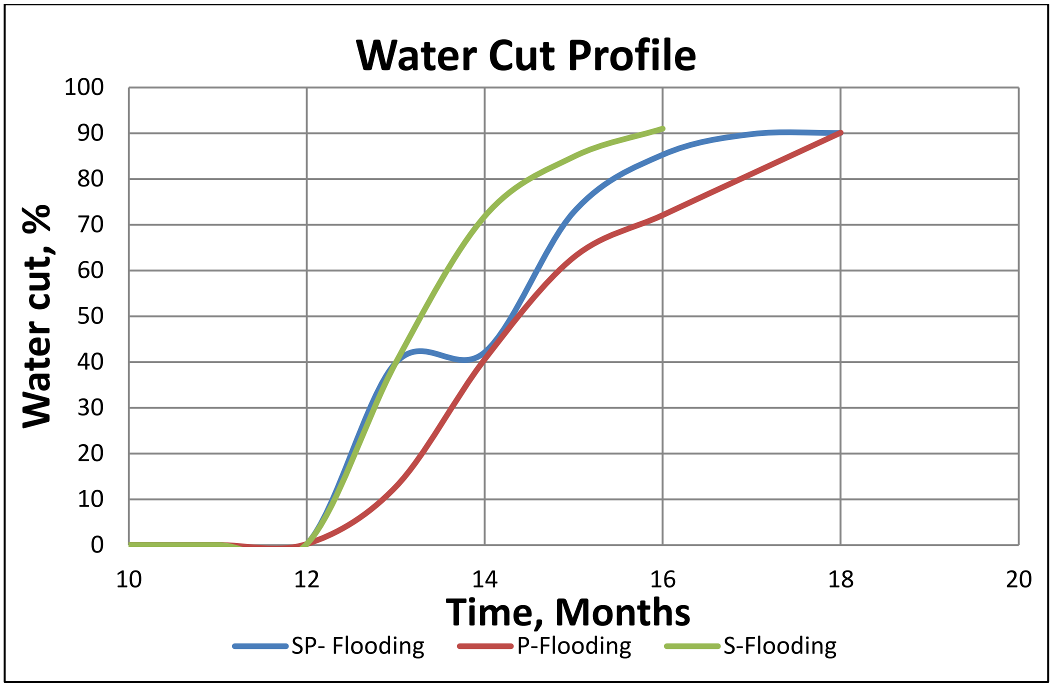


Figure 15

CHAPTER 5:

CONCLUSION AND RECOMMENDATION

- A successful simulation study has been performed to evaluate the performance of the Polymer-Surfactant flood in the NFR. The study utilized an 81x31x2 Cartesian model of 5-spot pattern, using Dual-porosity Dual-permeability approach by using CMG STARS simulator. Some assumptions are made on the study, includes;

    i. The reservoir is considered as light oil reservoir (black oil model).
    ii. Using DPDP model to capture the effect of the fractures in the field.
    iii. Rock and Fluid properties will be taken from a published data for a common carbonate fractured reservoir including capillary pressure and wettability conditions.
    iv. Assuming the polymer has both effect on reduction on IFT and altering the Wettability, in addition to increase the injected fluid viscosity.

- The study goals have been achieved by having around 60% recovery factor when using the SP slug. However, the Polymer injection alone gives better results in recovery comparing with the Surfactants.

RECOMMENDATIONS

- Based on the results obtained in this study, the following recommendations for the research are made;

i. Experimental research has to be conducted to validate the success of using SP slug, and to investigate the effect of injecting high IFT brine to the model for wettability alteration.

ii. A validation of field scale implementation is required, such as sensitivity or pilot test in a fracture porous medium.

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