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Numerical Simulation Of The Effects Of Phase Mobility Alteration On Waterflood Oil Recovery Process.

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Abstract

In this work, a model based on Eclipse 100 numerical simulator was developed to investigate the effect of phase mobility alteration during waterflooding operation. The model concept on the simulator was used for properties identical to the Niger Delta formation. Three case scenarios were considered in the study of the effect of phase mobility alteration on waterflood oil recovery - the analysis of the system on a natural drive; under intense water injection; and addition of different polymer concentrations to the injected water for phase mobility study. Precisely, polymer concentrations of 0.254, 0.525 and 0.702 lb/stb were added respectively to the model. The result showed that the addition of polymers at an optimum concentration led to a significant decrease in water cut of about 57%. This indicates that polymers reduce the relative permeability of the rock to water there by reducing water flow and fractions produced. From the result obtained, it was also found that the addition of polymers delayed the water-break through time and increased recovery. However, from the recovery plot, continuous addition of polymers did not necessarily lead to an exponential increase in oil recovery. Also continual increase in the concentration of polymers showed that the decrease in water cut was not significant thereby indicating the need to establish an optimal concentration for the case scenarios. 0.702lb/stb was established as the optimal polymer concentration for this study. The simulation result also indicated that a recovery factor of 38% was obtained as a result of using polymer flooding.

Keywords: Waterflood, Phase mobility, Permeability, Polymers, Concentration, Recovery Factor.

1.0 INTRODUCTION

Waterflooding is the most commonly used secondary oil recovery method. This is because water is inexpensive and readily available in large volumes and because of its effectiveness at substantially increasing oil recovery. The level of effectiveness of a waterflood depends on the mobility ratio of the oil and water, the geology and petrophysical properties of the oil reservoir. Waterflooding is effective because almost all reservoir rocks are either water-wet or mixed-wet. The depositional and diagenetic characteristics of a reservoir control major aspects of the water/oil displacement process. These characteristics can either enhance waterflood performance or have detrimental effects on the WOR as a function of time. Often, the details of a reservoir's internal geology are not known until production wells start producing injected water.

Gravity effects that is the interplay between the gravity/density effects and the geologic layering of a reservoir are important in waterfloods because at reservoir conditions, oil always is less dense than connate brine or injected water. This interplay can either help or hurt waterflood performance relative to a homogeneous system. Water will always move faster than oil in a two phase flow system.

Waterflooding is implemented by injecting water into a set of wells while producing from the surrounding wells. Waterflooding projects are generally implemented to accomplish any of the following objectives or a combination of them:

i. Reservoir pressure maintenance
ii. Dispose of brine water and/or produced formation water
iii. As a water drive to displace oil from the injector wells to the producer wells.

Over the years, waterflooding has been the most widely used secondary recovery method worldwide. Some of the reasons for the general acceptance of waterflooding are as follows (Satter *et al.*, 2008).

1. Water is an efficient agent for displacing oil of light to medium gravity,
2. water is relatively easy to inject into oil-bearing formations,
3. water is generally available and inexpensive, and
4. waterflooding involves relatively lower capital investment and operating costs that leads to favourable economics.

Waterflooding is generally implemented by following various types of well flooding arrangements such as pattern flooding, peripheral flooding, and crestal flooding, among others. Pattern flooding is used in reservoirs having a small dip (not flat- lying reservoirs) and a large surface area. Economic factors are the main criteria for the selection of a specific pattern geometry; these factors include the cost of drilling new wells, the cost of switching existing wells to a different type (i.e., a producer to an injector), and the loss of revenue from the production when making a switch from a producer to an injector. For instance, the direct-line-drive and staggered-line-drive patterns are frequently used because they require the lowest investment. However, if the reservoir characteristics yield lower injection rates than those desired, the operator should consider using either a seven- or a nine-spot pattern where there are more injection wells per pattern than producing wells as suggested by Craft and Hawkins, (1991).

While this discussion will be limited to the displacement of oil by water, the displacement processes and computational techniques presented have application to other oil recovery processes.

1.1 Mobility and mobility ratios

Fluid mobility is the ease with which the fluid moves through the reservoir. It encompasses rock and fluid properties. It is defined as the ratio of the fluid effective permeability to its viscosity, thus:$\lambda = \frac{K_e}{\mu}$. Therefore, for a given effective permeability, the mobility is higher with light fluid than more viscous fluid. Oil is usually more viscous than water, therefore, at the same effective permeability, water tends to be more mobile than oil and will tend to out run the oil.

Mobility ratio is defined as the mobility of the displacing phase divided by the mobility of the displaced phase. Mobility ratio is written as: $M = \frac{\lambda_{displacing}}{\lambda_{displaced}}$ Mobility ratios are typically defined with reference to saturations at specific locations of the displacement process. Mobility ratio is generally termed favorable or unfavorable depending on whether its value is less than or greater than unity. When M = 1, the mobilities of oil and water are identical and they encounter the same resistance to flow within the reservoir. In this case, since oil is as mobile as water, then there is a piston-like displacement of oil and hence, oil recovery is greatly enhanced. When M < 1, oil flows better than water and it is easy for water to displace oil; this condition generally results in high sweep efficiencies and good oil recovery.

Conversely, when M > 1, water flows better than oil and is not very effective in displacing oil. In general, sweep efficiency and oil recovery tend to decrease as mobility ratio increases. The most commonly encountered values of mobility ratios encountered during waterflooding range from 0.02 to 2 .0 (Craig, 1993).

2.0 METHODOLOGY

2.1 Conceptual Framework of Water Flooding

To account for the effect of mobility alteration on waterflooding operations, it is crucial to ascertain the degree of water produced from the producer resulting from injected displacement fluid (water) at the injector. It is important that the injected fluid remains downstream of the displacement fluid (reservoir hydrocarbon); technically, this is a case of the displacing fluid not overriding the displaced fluid.

Hence, predominant variables to consider is the degree of produced water (Water Cut). Recall, according to Leverett, (1971) a system of two immiscible fluids, oil and water is characterized by a water cut of:

$$f_w = \frac{q_w}{q_t} = \frac{q_w}{q_w+q_o} \qquad (1)$$

Where

f_w=fraction of water in the flowing stream, bbl/bbl

q_t = total flow rate, bbl/day

q_w = water flow rate, bbl/day`

q_o = oil flow rate, bbl/day

Considering a steady state flow of two immiscible and incompressible fluids through a vertical cylindrical porous media as shown in Fig. 1 below

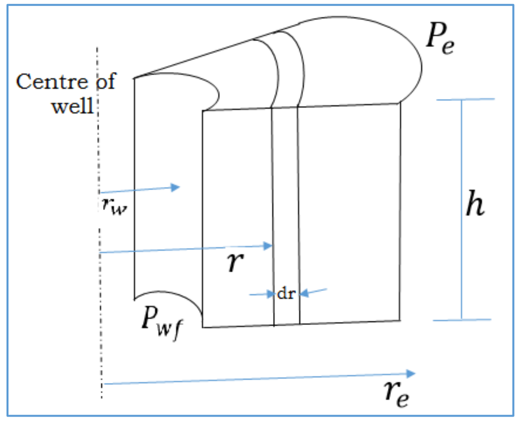

Figure 1: A Steady State Flow of Two Immiscible and Incompressible Fluids through a Vertical Cylindrical Porous Media.

Assuming a system that is homogeneous, Darcy's equation is prescribed as and is applicable to each fluid as

$$q_o = \frac{0.00708kh\,(P_2 - P_1)}{\mu_o B_o \ln\left({r_2}/{r_1}\right)} \qquad (2)$$

Using the reference pressure point and radii of P_e and P_{wf} and r_e and r_w respectively.

Where,

P_e = external/boundary pressure, psi

P_{wf} = wellbore flowing pressure, psi

μ_o = oil viscosity, cp

h = reservoir thickness, ft

B_o = oil formation volume factor, bbl/STB

r_e = external/boundary radius, ft

r_w = wellbore radius, ft

k = absolute permeability, md

q_o = oil flow rate, STB/day

Hence,

$$q_o = \frac{0.00708 k_o h\,(P_e - P_{wf})}{\mu_o B_o \ln\left({r_e}/{r_w}\right)} \qquad (3)$$

For any reference radius from centre of water injection, we have

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Volume 07 Issue 02
February 2020

$$q_o = \frac{0.00708 k_o h \,(P_e - P_{wf})}{\mu_o B_o \ln\left({}^{r}/_{r_w}\right)} \quad (4)$$

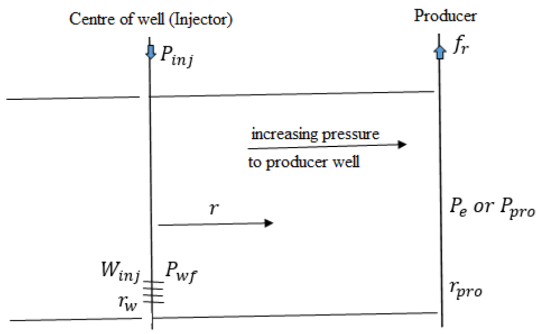

Figure 2: Schematic of an injector and producer with W_{inj} equals P_{wf}

Assuming W_{inj} pressure equals P_{wf} at the injector, for initial waterflooding (early process stage) $\left[\frac{d_p}{d_r}\right]_w$ equals zero, the resulting equation becomes:

$$M = \frac{(B_o f_r)^{-1}\Delta p}{\ln r - \ln r_w} \quad (5)$$

2.2 Building the Reservoir Model

Schlumberger's Eclipse 100 was used in the simulation for the impact of mobility parameter variation. Figure 1 is a 3D-image of the model. The simulator is a black oil simulator with implicit resolutions for 3D reservoir problems. It transforms non-linear equations to their linear algebraic equivalents and solves for desired parameters using a material balance algorithm. A typical under-saturated Niger Delta waterflood candidate oil reservoir with OOIP of 35.6MMSTB with a weak aquifer was used to simulate for mobility alteration performance.

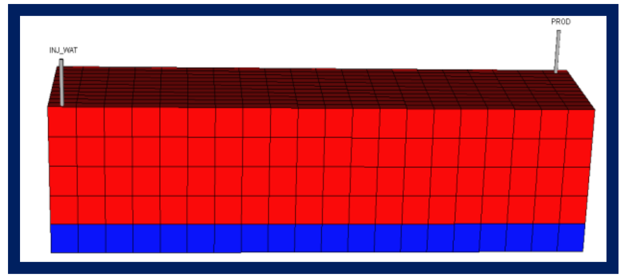

Figure 3: 3D-image of the model.

Three case scenarios was considered in a quest to investigate the effect of phase mobility alteration, which incorporates an analysis of the system for a natural drive case, a water injection case and water plus polymer injection at different concentrations.

In the areal plane of the reservoir, the dimensions were determined. The grid block describing the XYZ direction is 20 x 15 x 5 which was generated using Cartesian coordinates grid cells.
Three different permeability values were assigned to each block, corresponding to the three coordinate directions. The x- and y-direction permeabilities were assumed to be identical and identified with the horizontal or lateral permeability. The z-direction is then identified with the vertical permeability. A multiplier of 0.1 was used on the x-direction to determine the z-direction permeability.
The injector was placed at cell (1, 11, 1) while the producer was placed at cell (20, 1, 1)

2.3 Dynamic Modeling

Dynamic modeling describes the physical movement of fluids within a reservoir over time. The flow of fluids is governed by three basic physical principles:

I. Mass is neither created nor destroyed, that is Conservation of Mass.
II. The rate of change of momentum of a portion of the fluid equals the force

applied to it, or Conservation of Momentum.

III. Energy is neither created nor destroyed, that is Conservation of Energy.

The dynamic modeling in eclipse takes a particular trend as listed below;

1. PVT Section
2. SCAL Section
3. Initialization Section
4. Schedule Section.

Table 1: Reservoir Input Data for Simulation

Start Date	**01/01/2019**	
Reservoir Thickness	100ft	
Reservoir Areal	300ft x 200ft	
	PROPERTIES	**VALUE**
Average Reservoir properties	Depth, ft	6450
	Porosity	0.25
	Permeability (X and Y), md	800
	Vertical permeability (Z), md	80
	Thickness, ft	100
	NTG	0.9
	Initial Reservoir Pressure, psi	4500
	Initial water saturation	0.35
	Water compressibility, 1/psi	2.944768E-6
	Rock compressibility, 1/psi	5.477233E-6
	Oil saturation fraction	0.85
Initial fluid properties	API (API Oil)	36
	Solution gas oil ratio, scf/stb	900
	Initial formation volume factor, rb/stb	1.505
	Oil viscosity, cp	0.4
	Oil density, kg/m^3	844.78
	Saturation pressure, psi	3694
	Reservoir Temperature (°F)	200

2.2.1 SCAL (Special Core Analysis) Section

In this section, the relative permeability and capillary pressure of each of the fluid to another is modeled. SWFN and SGFN were used to enter the two-phase oil-water relative permeability and gas-oil relative permeability respectively. The relative permeabilities were defined as functions of the water saturation. For the case of water injection, a second saturation table was also created for the imbibition process.

2.2.2 Initialization Section

At time zero, before any flow occurs in the reservoir, the saturation and pressure distribution in the reservoir must be such that the fluids are in gravity equilibrium, i.e. a no-flow situation. The initialization of the models was done with the EQUIL keyword. By this keyword Eclipse calculated the capillary and fluid gradients, and hence fluid saturation densities in each cell.

Table 2: Datum Depth, OWC and Pressure at Datum Depth

Datum Depth (ft.)	Oil-Water Contact (ft.)	Pressure at Datum Depth (psi)
6250	6450	4500

2.2.3 Schedule Section

Information about the well and production history is built in this section.
Basically, this section comprises of three different kinds of data:

1. Well specification (WELSPECS)
2. Completion data (WCOMPDAT)
3. Production and injection data (WCONPROD, WCONINJE)
4. Time Stepping (TSTEP)
5. Injection well Polymer/salt concentration (WPOLYMER).

2.2.3.1 Well specification (WELSPECS)

Well specification includes the static properties of the well such as the well name, location, dimensions etc. This must be specified before any other well data can be defined.

Table 3: Well Specifications of well PROD

Well	Location (i, j)	Preferred phase
PROD	20, 1	Oil

2.2.3.2 Well Completions (COMPDAT)

The keyword is used to specify grid cells that are open to flow to the well. A complete description of a well's completion is defined using several records.

Table 4: Perforation intervals of well PROD

Well	Perforation interval
PROD	1- 4

2.2.3.3 Production/injection data (WCONPROD/WCONJINE)

These keywords were used to specify production/injection rates, guidelines and constraints. If no constraints are violated, the rate will be determined by the primary guide, defined by the Control mode item. The production wells have their data specified in the WCONPROD keyword while the injection wells have their data specified with WCONINJE.

Table 5: Production Wells Control Data

Well	Wellbore ID (in)	Control mode	Oil rate (Stb/day)
PROD	0.666	Oil Rate (ORAT)	2000

Table 6: Water Injection Wells Control **Data**

Well	Location	Control mode	Injection rate (Stb/day)
INJ_WAT	1, 11, 1-5	Liquid Rate (RATE)	2000

2.2.3.4 Time Stepping (TSTEP):

In running the simulation, a time step of one year for a run of 38 years was used in this work. Time stepping in the SCHEDULE section allows for the specification of milestones (times or dates) of special interest.

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Volume 07 Issue 02
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2.2.3.5 Injection well polymer/salt concentration (WPOLYMER)

Controlling the mobility of the injected fluid at the injector well is done using this key word. Here salt concentration and polymer concentration can be altered.

3.0 RESULTS AND DISCUSSION

The result of the numerical simulation is displayed in this section. In this result, different cases were carried out to ascertain the impact of the objectives of this study. The first case that was run is that of:

CASE 1: an oil production on natural drive
CASE 2: an oil production scenario with water injection.
CASE 3: an oil production scenario with polymers added to the water at different concentration to investigate phase mobility.

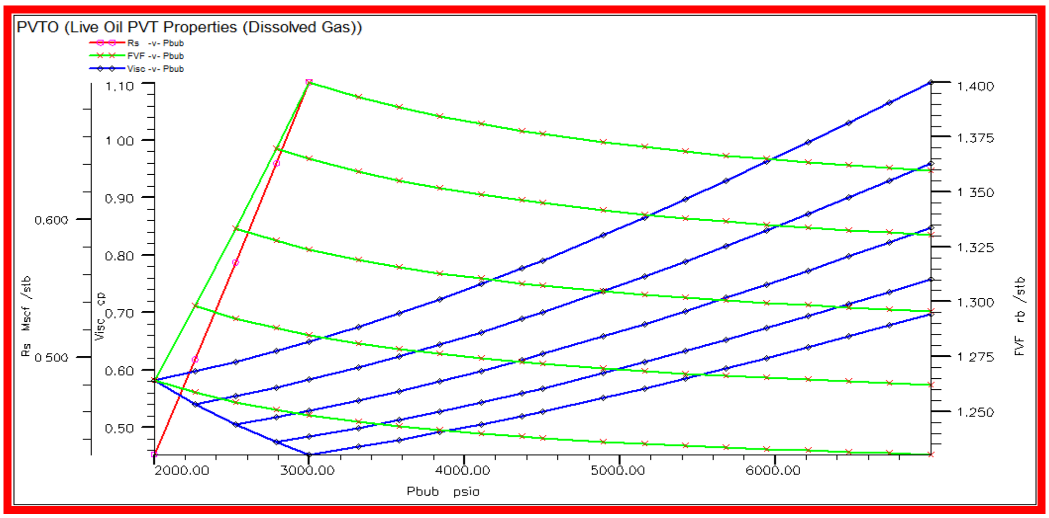

Figure 4: PVT Diagram of the Oil Phase

Table 7: Water-oil Relative Permeability Phase

Sw	Krw	Kro	Pc (psi)
0.35	0	1	8.70228
0.44	0	0.166375	4.35114
0.45375	0.000122	0.111458	2.465646
0.4675	0.001953	0.070189	1.377861
0.48125	0.009888	0.040619	0.754198
0.495	0.03125	0.020797	0.449618
0.50875	0.076294	0.008774	0.261068
0.5225	0.158203	0.0026	0.174046

0.53625	0.293091	0.000325	0.11603
0.55	0.5	0	0.014504
0.8	1	0	0

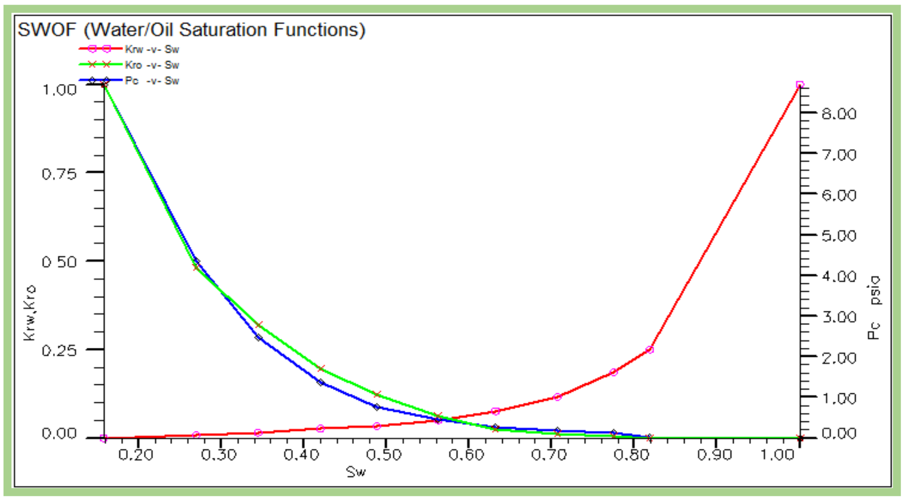

Figure 5: Water-oil Relative Permeability Curve Phase

Table 8: Gas-oil Relative Permeability Phase

Sg	Krg	Kro	Pc (psi)
0	0	1	0
0.17	0	0.411	0.0145038
0.24	0.03	0.292	0.0290076
0.3	0.075	0.2	0.0580152
0.37	0.12	0.12	0.145038
0.43	0.18	0.064	0.2755722
0.5	0.289	0.023	0.4931292
0.56	0.4	0.003	0.870228
0.7	0.6	0	1.740456
0.8	0.65	0	1.940456
0.9	0.7	0	2.040456

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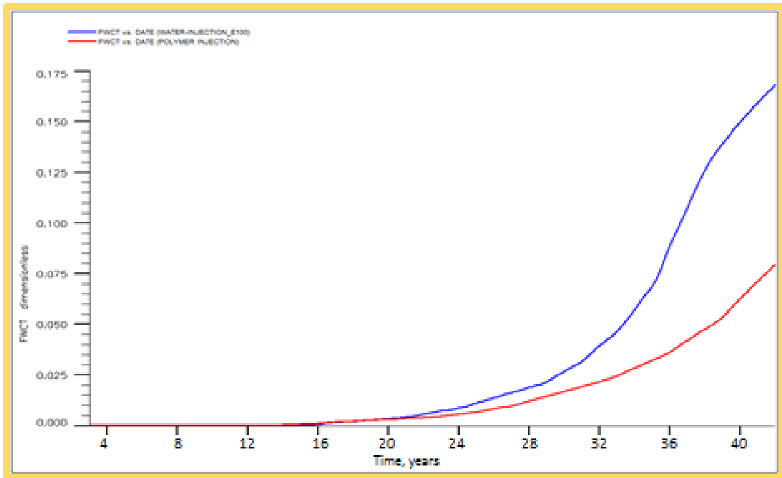

Figure 6: Water Cut Profile for the Water Injection and Polymer Injection

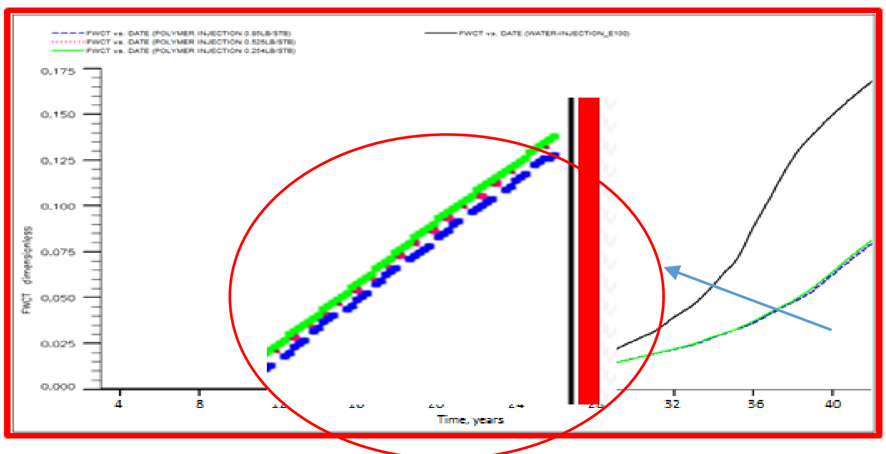

Figure 7: Water Cut Profile for Different Polymer Concentration

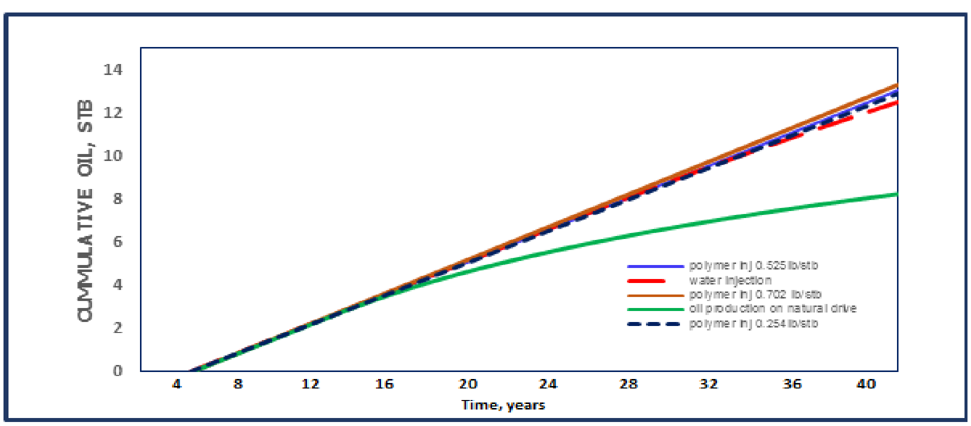

Figure 8: Cumulative Oil Production of all Cases

4.0 CONCLUSION

The research conducted is a case study using a conceptual model built using ECLIPSE 100, a numerical simulator to demonstrate the effect of phase mobility during water flooding operation. The process involved building a conceptual model on eclipse and using properties identical to the Niger Delta formation. The results obtained was done for three cases which involved natural drive, water injection and water injection + polymers. The polymers added was used to investigate phase mobility alteration effect by varying the concentration of polymers. Different polymer concentrations were added to the injected water to investigate phase mobility. Concentrations of 0.254, 0.525 and 0.702 lb/stb were added respectively to the model. The result showed that the addition of polymers at a given optimum concentration (0.702 lb/stb) led to a significant decrease in water cut of about 57%. This indicates that polymers reduce the relative permeability of the rock to water there by reducing water flow and fractions produced. From the result obtained also, the addition of polymers delayed the water-break through time and increased recovery.

However, from the recovery graph, continuous addition of polymers doesn't necessarily lead to an exponential increase in oil recovery. Also continual increase in the concentration of polymers showed that the decrease in water cut was not significant thereby indicating the need to find an optimal concentration for each pilot case.

The simulation result also indicated that a recovery factor of 38% was obtained as a result of polymer addition. This result is in line with the results obtained by Movahedi et al. (2015) and Murad and Abdulfarraj (2011) which further justifies that the addition of polymers at an optimum concentration has the potential of increasing the recovery factor. However, beyond the optimal concentration of polymer, a negligible recovery factor was noticed when increasing concentration. This can help the oil and gas industry in decision making and forecasting for various injection scenario.

5.0 Recommendations

Simulations are only mathematical solutions to real life problems. As such, the last step of every such simulation is a field pilot test. Also water flooding pattern should be investigated while considering phase alteration to investigate its effect on flooding operations in future research.

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APPENDIX I

SOURCE CODE FOR PRODUCTION FORECAST

```
---------------------------------------------------------------------------
-- Office Simulation File (DATA) Data Section Version 2005A Apr 19 2005
---------------------------------------------------------------------------
--
-- File: WATER-INJECTION_E100.DATA
-- Created on: 03-Sep-2018 at: 23:46:52
--
--
*****************************************************************************
--  *                                                                 WARNING
*
--  *                           THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
*
--  *              ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.
*
--
*****************************************************************************
--

RUNSPEC

TITLE
```

```
title

START
 1 'JAN' 2019 /

FIELD

GAS

OIL

WATER

SUMMARY

INCLUDE
'WATER-INJECTION_SUM.INC'   /


SCHEDULE

INCLUDE
'WATER-INJECTION_SCH.INC'   /


END

--
-- ---------------------------------------------------------------------------
---
-- Office Simulation File (DATA) Data Section Version 2005A Apr 19 2005
-- ---------------------------------------------------------------------------
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-- File: API_E100.DATA
-- Created on: 03-Sep-2018 at: 23:49:32
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--
*****************************************************************************
--  *                                                                 WARNING
*
-- *                          THIS FILE HAS BEEN AUTOMATICALLY GENERATED.
*
-- *              ANY ATTEMPT TO EDIT MANUALLY MAY RESULT IN INVALID DATA.
*
--
*****************************************************************************
--

RUNSPEC

TITLE
```

```
title

START
 1 'JAN' 2019 /

FIELD

GAS

OIL

WATER


SUMMARY

INCLUDE
'API_SUM.INC'  /

SCHEDULE

INCLUDE
'API_SCH.INC'  /

 END
```