Modeling and Simulation of Reservoir Pressure Associated with Emulsions Transport Near Wellbore for Enhanced Oil Recovery

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ABSTRACT

The most important area of a producing reservoir is the near wellbore which is within 5fts into the formation. All fluids have to flow through it, usually at high flow rates. Problems associated with formation damage near wellbore occur frequently, resulting in permeability impairments and increased pressure losses. During drilling, emulsion formation affects reservoir deliverability and ultimate recovery. Most of the existing methods to aid mitigation near oil well damages involve the use of empirical models. Conducting experiments, frequent shut down of wells for proper well test analysis and pressure maintenance are highly expensive and time consuming. Therefore, this paper aimed at optimizing reservoir pressure using cross section comparisons of mathematical tools and experimental for improved emulsion transport near wellbore. Formation damage mechanisms are highlighted for the purpose of reservoir engineers. The engineers must be vigilant about the potential formation damages near wellbore and then can mitigate the impact of damages by understanding its mechanisms how various types of damages might impact production, Assessment, control and remediation. The transient hydraulic diffusivity partial differential equations (THDPDE) models developed. The model equations were resolved using finite difference method and implemented by writing codes in MATLAB language. The solutions obtained were validated using field data and experimental work. The results indicated pressure depletion over time without injection but increases under the influence of increased injection rates enhancing the oil recovery. Experiments were also carried out to evaluate the effectiveness of the
emulsions as displacing fluid for enhanced oil reservoir. In this paper, a new modeling scheme is proposed and is based entirely on cross section comparisons involving modification of Darcy’s equation with experimental work in an attempt to optimize reservoir pressure and improved oil-in-water emulsions near wellbore. The knowledge that oil-in-water emulsion type exists and that a new scheme to uniquely characterize the near wellbore damage is developed. The present authors suggest cross section comparisons of both modeling and experimental section for predictions of the data in the study area. Numerical simulation has proved to be effective in simulating emulsions near wellbore. The formulated models indicate pressure depletion over time, but increased thereafter, resulting to increased oil recovery and significant improvement in emulsions transport near wellbore.

**Keywords:** Modeling, Simulation, MATLAB language, wellbores, drilling, emulsion, oil

1. INTRODUCTION

The most important region of a producing reservoir is the zone within 5 meters of a wellbore. All fluids have to flow through it, usually at high flow rates compared to that in the deep reservoir away from the wellbore (Civan, 2015, Ali-A-Tag et al. 2018). Exactly how and what route the oil-in-water emulsions flow to the perforations and hence into the wellbore is not well understood. The near wellbore formation permeability significantly affect pressure profiles and well deliverability as well as production rates. This near wellbore is usually damage due to formation damage mechanisms (Irene Faegested, 2013).

Formation damage is a condition most commonly caused by wellbore fluids used during drilling, completion and workover operations. It impairs the permeability of reservoir rock near wellbore, thereby reducing the natural productivity of the reservoir. Although, the severity of formation damage may vary from one well to another, any reduction in recovery potential is unwanted and the effects of formation damage can have negative impact on oil recovery (Civan, 2000, 2007; Bradley et al. 2018).

2. FORMATION DAMAGE MECHANISMS

The main four categories of formation damage mechanisms are mechanical, chemical, biological and thermal. Damage that induces a reduction in permeability as a result of direct, mechanical interactions between equipment or fluids and the formation is mechanical damage.

Common mechanical formation damage mechanisms include:

a) Fines migration- fines particle migration perhaps most common mechanism refers to the motion of naturally existing particulates in the pore spaces system caused by high fluid shear rate (Amanda et al. 2018).

b) External solid entrainment- When particles from introduced fluids enter and plug formation pores surrounding the wellbore as well as variety of suspended solids in drilling fluids. Damage of this type is a major concern in formation capable of enhancing rapid formation filter cake (Abdullah, 2006).

c) Phase trapping and blocking- Phase trapping and blocking is related to a combination of adverse capillary pressure and relative permeability effects. These wellbore fluids
may contact a formation and cause a reduction in water saturation (Irene Feargested, 2013).

d) Perforation damage- The detonation of perforation charges may result in the creation of crushed zone and generate mobile rock grains possibly reducing permeability and creating perforating overbalanced that may cause significant impact on damage effects (Abdullah et al. 2013).

e) Gazing- this refers to direct damage to the wellbore face caused by drill bits interactions or poor rotary bits in a poor hole cutting situation, resulting in cutting of fines particles into the formation face (Abdullah, 2006).

Chemical formation damage mechanisms are generally divided into adverse rock-fluid interactions, adverse fluid-fluid interactions and near wellbore wettability alteration:

a) Clay swelling- this is a common damage mechanism in which hydraulic materials in the formation, such as reactive smectite and mixed layer clays. This swelling can severely reduce permeability when clay line the pore throats of a formation (Bradley et al. 2018).

b) Chemical adsorption and dissolution-formation dissolution occur in formation containing components that are soluble in water-based fluids. This condition may lead to a collapse of the wellbore wall (Bradley et al. 2018). Formation dissolution can be avoided.

c) Emulsions- Crude oil is seldom produced alone. It is generally comiled with water, which creates a number of problems during drilling and oil production. Produced water occur in two ways-as free water and in the form of emulsions either water-in-oil emulsion (water droplet in a continuous oil phase) or oil-in-water emulsion (oil droplet in a continuous water phase) these type of emulsions can exhibit very high viscosity and may result in blockage of pores near wellbore (Ajay et al. 2010; Deepa et al. 2017).

d) Scale formation- scale is as a result of the abnormal behavior of calcium carbonate which dissolves better in hot water than cold, it is less soluble as temperature increases. So when hard water is heated, the calcium carbonates can no longer stay dissolved but precipitates or fall out of the water as a scale on the face of the wellbore (Abdullah, 2006)

Biological formation damage mechanisms refer to problems created by the introduction of bacteria and nutrient stream in the reservoirs (Civan, 2007) although most common associated are bacteria contamination. This mechanism with bacteria entrainment has three major damage mechanisms which include

a) Plugging - most bacteria secrete a viscous polysaccharide polymer as a byproduct of life cycle which may be absorb and gradually plugged the formation.

b) Corrosion - some type of bacteria set up an electro kinetic hydrogen reaction which can result in pitting and stress cracking on the metallic surface equipment.

c) Toxicity - certain bacteria called anaerobic bacteria in the formation create toxic hydrogen sulfide gas.

Thermal formation damage mechanism refers to formation damage due to in-situ combustion. Thermal degradation of oil and rock compound that contain sulfate, at temperature above 200 °C (Civan, 2015). These could result to Mineral transformation and mineral dissolution.
3. Indicators and Effects of Formation Damage

If a well is producing at lower rate than expected, the source of the reduction must be determined before corrective measures can be attempted. If it is determined that formation damage is responsible for reduced productivity, several techniques can be used to verify the cause of the problem. Permeability impairment, skin damage and decrease of well performance are all indicators of formation damage. Skin damage is a measurable reduction of permeability in the vicinity of the wellbore. Scale precipitation, reduction of permeability near wellbore are skin effects and if the skin is not removed by remedial measure, such as acid stimulation or modeling the impact of damage, it will reduce well productivity. The ability to produce fluids from a reservoir is strongly affected by near wellbore permeability. Hence formation damage may severely reduce productivity.

This paper aims to improve reservoir pressure through our understanding of the skin effects that are prone to emulsions arising from chemical damage mechanisms near wellbore. Emulsion being one of the causes of formation damage posed a serious problem to ease of flow in oil reservoirs. Problems associated with emulsion transport near wellbore is a serious issue and this occur frequently and resulted in permeability impairment and increase in pressure losses. Most of the existing methods to aid mitigation or manage the near wellbore damage involve experiment and use of empirical models. Conducting experiments, frequent shut down of wells for proper well test analysis and pressure maintenance as required in existing analytical or semi analytical models are highly expensive and time consuming. Hence this study set to optimize reservoir pressure which tends to ease flow of oil-in-water emulsion in a typical Brown field for improved hydrocarbon recovery.

This paper also presents Finite Difference Method for transport of oil-in-water emulsion during pressure and saturation changes in the reservoir for homogeneous and isotropic porous media within a regular boundary domain. Although, reservoir pressure during lost circulation are governed by partial differential problems on mass transport phenomena focusing on reservoir engineering problem (Marttia Aleardi, 2018). The application of methodology is imbedded in a single well sealed reservoir.

4. PROBLEM FORMULATION

Emulsions is one of the causes of formation damage and as such the hydraulic diffusivity partial differential equation that describes the flow of oil-in-water emulsions is derived assuming the fluid is immiscible, disperse oil droplet in water, fluid is non-Newtonian, emulsions are viscosity dependent, flow is horizontal and no reaction between oil-in-water emulsions and permeable rock hence, the presence of gas is negligible.

The Darcy’s law can be used together with the mass conservation law and equation of state to obtain an expression for the transient hydraulic diffusivity partial differential equation (THDPDE) for oil-in-water emulsion flow in porous and permeable media (Macelo et al. 2013; Byrne et al. 2011). The material balance conservation of mass and the continuity equation in porous medium is given by

\[
\frac{\partial \rho v_x}{\partial x} + \frac{\partial \rho v_y}{\partial y} = - \frac{\partial (\phi \rho)}{\partial t}
\] (1)
Darcy equations along the $x$ and $y$ axis given as

$$v_x = -\frac{k \partial p}{\mu \partial x} \quad \text{and} \quad v_y = -\frac{k \partial p}{\mu \partial y}$$

(2)

where $v_x, v_y$ are flow rate, $\rho$ fluid density, $\phi$ is the porosity, $\mu$ is the viscosity, $k$ is the absolute permeability of the porous medium.

The Darcy equations (2) were modified in order to capture the damage zone where oil-in-water emulsions filled the passage of flow. This was accomplished by employing Hawkins’s equation (3 and 4) (Hawkins, 1956).

$$s_d = \left(\frac{k_n}{k_s} - 1\right) \ln \left(\frac{r_s}{r_w}\right)$$

(3)

$$s_f = \left(\frac{k_n}{k_s} - 1\right)$$

(4)

Figure 1. Permeability of damaged and undamaged zones near wellbore (Civan, 2000)

The contrast reveals the extent of permeability damage between $k_s$ and $k_n$. However, if a well is neither damaged nor stimulated $K_s = K_n$ and $S_f = 0$ (Civan, 2015). Therefore $K_s$ and $K_n$ indicate the significant of skin effect in Hawkin’s equation (3 and 4). Where $s_d$ is the skin damage, $s_f$ is the skin factor, $r_s$, $r_w$ and $r_e$ extent drainage radius, wellbore radius and drainage radius, $k_s$ and $k_n$ are the skin and normal permeability.

Hence equation (2) is modified to capture the damage zone in Figure (1). Substituting the skin factor equation (4) in place of $k$ into equation (2) given
\[ v_x = -\frac{k \partial p}{\mu \partial x} = \frac{-(k_n - k_s)}{\mu} \frac{\partial p}{\partial x} \]

\[ v_y = -\frac{(k_n - k_s) \partial p}{\mu k_s} \quad \text{and} \quad v_y = -\frac{(k_n - k_s) \partial p}{\mu k_s} \]

Equation (1) is the continuity equation and since density is constant, equation (1) becomes:

\[ -\rho \frac{\partial}{\partial x} \left( \frac{(k_n - k_s) \partial p}{\mu k_s} \right) - \rho \frac{\partial}{\partial y} \left( \frac{(k_n - k_s) \partial p}{\mu k_s} \right) = -\frac{\partial (\rho \phi)}{\partial t} \]

\[ \rho \frac{(k_n - k_s)}{\mu k_s} \frac{\partial^2 p}{\partial x^2} + \rho \frac{(k_n - k_s)}{\mu k_s} \frac{\partial^2 p}{\partial y^2} = \frac{\partial (\rho \phi)}{\partial t} \]

The equation of state assumed a fluid constant compressibility defined equation (7) and the right hand side of equation (6) becomes:

\[ c = -\frac{1}{v} \frac{dv}{dp} = \frac{1}{\rho} \frac{\partial \rho}{\partial p} \]

\[ c \rho dp = d\rho \Rightarrow C_t = c \rho = \frac{\partial \rho}{\partial p} \]

\[ \rho \frac{(k_n - k_s)}{\mu k_s} \frac{\partial^2 p}{\partial x^2} + \rho \frac{(k_n - k_s)}{\mu k_s} \frac{\partial^2 p}{\partial y^2} = \phi \frac{\partial p}{\partial p} \frac{\partial p}{\partial t} + \rho \frac{\partial \phi}{\partial t} \]

(8)

Since porosity \( \phi \) is constant and \( C_t \) in equation (7) substituted in equation (8) gives

\[ \frac{(k_n - k_s)}{\mu k_s} \left[ \frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2} \right] = \phi C_t \frac{\partial p}{\partial t} \]

\[ \frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2} = \frac{\phi C_t k_s \partial p}{(k_n - k_s) \partial t} \]

(9)

The new (THDPDE) governing the flow of oil-in-water emulsions with one injection well is given with boundary conditions, modified Darcy equations and the auxiliary equations

\[ \frac{\partial^2 p(x,y,t)}{\partial x^2} + \frac{\partial^2 p(x,y,t)}{\partial y^2} + q_{wi}(x,y,t) = \frac{\mu c_t k_s}{(k_n - k_s)} \frac{\partial p(x,y,t)}{\partial t} \quad \{0 \leq x \leq a, \quad t > 0\} \]

\[ \{0 \leq y \leq b, \quad t > 0\} \]

(10)

\[ \frac{\partial p}{\partial x}(x,y,t) = 0 \quad \{y = 0, \quad t > 0\} \]

\[ \{y = b, \quad t > 0\} \]

(11)
\[
\frac{\partial p}{\partial y}(x,y,t) = 0 \quad \text{at} \quad \begin{cases} x = 0, \\ x = a, \quad t > 0 
\end{cases}
\]

\[
p(x, y, 0) = p_0 \quad \text{in} \quad \begin{cases} 0 \leq x \leq a, \\ 0 \leq y \leq b, \quad t = 0 
\end{cases}
\]

Modified Darcy equations

\[
V_x = \left(\frac{k_n - k_s}{\mu k_s}\right) \frac{\partial p}{\partial x} = \frac{1}{\mu S_f} \frac{\partial p}{\partial x}
\]

\[
V_y = \left(\frac{k_n - k_s}{\mu k_s}\right) \frac{\partial p}{\partial y} = \frac{1}{\mu S_f} \frac{\partial p}{\partial y}
\]

Auxiliary equations

\[
c_t = s_w c_w + s_o c_o + c_f
\]

\[
s_d = \left(\frac{k_n}{k_s} - 1\right) \ln \frac{r_s}{r_w}
\]

\[
S_f = \frac{k_n}{k_s} - 1 = +\text{ve} \quad \text{damage occur for } k_s < k_n
\]

\[
S_f = \frac{k_n}{k_s} - 1 = -\text{ve} \quad \text{No damage occur for } k_s > k_n
\]

This work proposes finite difference method of solution for homogeneous and isotropic porous media.

5. EXPERIMENTAL SECTION FOR EMULSION FORMATION AND WATER FLOODING TEST

The models formulated and implemented were validated by carrying out laboratory experiments for emulsion formation and emulsion flooding. The experiments were performed in Central Research Laboratory of Yaba College of Technology Lagos, Nigeria.

Materials used:

- Distilled water
- Gear oil (EPX 90) with specific gravity 0.905 and viscosity 197 centistokes at 30 °C and 17.3 centistokes at 100 °C
- Ashpaltenes
- Resins
- Cyclone Homogenizer
- Silverson Laboratory mixer
- Tengmeng Laboratory mixer
5. 1. Procedure (Emulsion Formation)

Five batches of emulsion comprising mixture of 500 ml volume of oil and 50 ml volume of distilled water (mixed using Silverson laboratory Mixer) were prepared. Each mixture was agitated rigorously for 20 minutes to make it homogenous. The quality of the prepared emulsions was improved by injecting 0.5 Pore Volume Resins rather than Ashpaltenes using a standard three blade propeller Tengmeng Laboratory Mixer. This is because the latter is involved in the formation of fine solids which may lead to the plugging of pore spaces in the reservoir matrix and wellbore given rise to formation damage during production (Ali et al., 2000). Furthermore, resin was considered to be a good absorbent, a reagent that stabilizes water-in-oil emulsion and soluble in colloidal solution for stability (Reference). The emulsions were then left to stand in its separation flask for four hours and the bottom part was separated out. The separation flask can easily lead to the separation of two fluids based on their density. Readings of viscosity of emulsion were taken at 600 rpm and 300 rpm respectively by the Viscometer and the corresponding pressure variations were also measured using barometer.

5. 2. Procedure (Water Flooding Test)

Simplified water flooding system based on Civan (2015), comprising core sample, core holder to maintain the sample at high-pressure control system (overburden), inlet and outlet pumps, Magnetic Resonsnce Inspector to monitor the distribution of water and oil with sand pack, cylinder for holding gear oil was set up. The gear oil with acid number of 0.038mg KOH/g, gravity of 38.86º API and viscosity of 119 scp at 30 ºC. The sand pack holder was first tightly packed with sand using brine solution and absolute permeability was then measured. It was thereafter flooded with the gear oil with an injection pressure of 500 psig and irreducible water saturation and initial oil saturation was measured by material balance. The sand pack was allowed to rest for two days and then water flooded with 300 psig injection pressure and substantial amount of oil was recovered. Additional amounts oil was recovered with continuous flooding until water cut reached above 95%. Darcy’s equation was used to measure the effective permeability to oil ($K_0$) and effective permeability to water ($K_w$). Irreducible water saturation ($S_{wi}$) and residual oil saturation ($S_{or}$) was also measured. Porosity and absolute permeability was measured for each sample experiment. It is important to emphasize that, for each test, fresh sand was packed to ensure the same wettability and completely saturated with water by continuous flooding.

6. SOLUTION METHODOLOGY

The solution methodology presented here intends to discretize the (THDPDE) for oil-in-water emulsions (10) flowing through a homogeneous and isotropic porous medium. The algorithm that approximates the solution problem was done by dividing the domain into
uniform grid for approximately different time step. Where $q_{wl}$ are the source terms for injection/production well and time is considered in the formation to account for injection and/or production well(s).

Equation (10) was discretized by using finite forward difference in two-dimensions employing the alternating direction implicit (ADI) finite difference (Peaceman and Rachford, 1955).

$$
\left( \frac{p_{i+1,j}^{k+1} - 2p_{i,j}^{k} + p_{i-1,j}^{k}}{\Delta x^2} \right) + \left( \frac{p_{i,j+1}^{k+1} - 2p_{i,j}^{k+1} + p_{i,j-1}^{k+1}}{\Delta y^2} \right) + q_{wsc} = \frac{\phi \mu c_t k_s}{(k_n - k_s)} \left( \frac{p_{i,j}^{k} - p_{i,j}^{k+1}}{\Delta t} \right) 
$$

(17)

$$
\frac{\Delta t}{\Delta y^2} \left( p_{i,j}^{k+1} - 2p_{i,j+1}^{k+1} + p_{i,j-1}^{k+1} \right) - \frac{\phi \mu c_t K_s}{(k_n - k_s)} \left( \frac{p_{i,j}^{k} - p_{i,j}^{k+1}}{\Delta x^2} \right) = - \frac{\phi \mu c_t K_s}{(k_n - k_s)} p_{i,j}^{k} - p_{i+1,j} - 2p_{i,j}^k + p_{i-1,j}^k - q_{wsc} \Delta t
$$

$$
ryp_{i,j+1}^{k+1} - \left( 2ry + \frac{\phi \mu c_t K_s}{(k_n - k_s)} \right) p_{i,j}^{k+1} + ry p_{i,j-1}^{k+1} = - \frac{\phi \mu c_t K_s}{(k_n - k_s)} p_{i,j}^{k} - rx \left( p_{i+1,j}^k - 2p_{i,j}^k + p_{i-1,j}^k \right) - q_{wsc} \Delta t
$$

(18)

All the terms on the left hand side are unknowns while those on the right hand side are known-initial conditions and upwardly solved variables time step counter. The second direction solves for the temporal pressure variation along the y axis, while the discrete equation below solves for the x-direction.

$$
\left( \frac{p_{i+1,j}^{k+1} - 2p_{i,j}^{k+1} + p_{i-1,j}^{k+1}}{\Delta x^2} \right) + \left( \frac{p_{i,j+1}^{k+1} - 2p_{i,j}^{k+1} + p_{i,j-1}^{k+1}}{\Delta y^2} \right) + q_{wsc} = \frac{\phi \mu c_t K_s}{(k_n - k_s)} \left( \frac{p_{i,j}^{k+2} - p_{i,j}^{k+1}}{\Delta t} \right) 
$$

(19)

$$
\frac{\Delta t}{\Delta x^2} \left( p_{i+1,j}^{k+2} - 2p_{i,j}^{k+2} + p_{i-1,j}^{k+2} \right) - \frac{\phi \mu c_t K_s}{(k_n - k_s)} \left( \frac{p_{i,j}^{k+1} - p_{i,j}^{k+1}}{\Delta t} \right) - \left( \frac{p_{i,j+1}^{k+1} - 2p_{i,j}^{k+1} + p_{i,j-1}^{k+1}}{\Delta y^2} \right) = \frac{\phi \mu c_t K_s}{(k_n - k_s)} \left( p_{i,j}^{k+2} - p_{i,j}^{k+1} \right) - q_{wsc} \Delta t
$$

$$
rx \left( p_{i+1,j}^{k+2} - 2p_{i,j}^{k+2} + p_{i-1,j}^{k+2} \right) - \frac{\phi \mu c_t K_s}{(k_n - k_s)} p_{i,j}^{k+2} = - \frac{\phi \mu c_t K_s}{(k_n - k_s)} p_{i,j}^{k+1} - ry \left( p_{i,j+1}^{k+1} - 2p_{i,j}^{k+1} + p_{i,j-1}^{k+1} \right) - q_{wsc} \Delta t
$$
\[
\left(r_x p_{i+1,j}^{k+2} - \left( 2r_x + \frac{\phi \mu c i K_s}{(k_n - K_s)} \right) p_{i,j}^{k+2} + r_x p_{i-1,j}^{k+2} \right) = -\frac{\phi \mu c i K_s}{(k_n - K_s)} p_{i,j}^{k+1} - r_y \left( p_{i,j+1}^{k+1} - 2p_{i,j}^{k+1} + p_{i,j-1}^{k+1} \right) - q_{WSW} \Delta t
\]

Equation (20)

\[r_x = \frac{\Delta t}{(\Delta x)^2}; \quad r_y = \frac{\Delta t}{(\Delta y)^2}; \quad \Delta t = \frac{T}{N}; \quad \Delta x = (x_f - x_0); \quad \Delta y = (y_f - y_0)\]

T – Total simulation time. N – Number of discrete time steps used for simulation. Equations (18) and (20) are symmetric along the x − y axis.

7. RESULTS AND DISCUSSION

The implementation of the solution was carried out on MATLAB. The field data specification and validation using synthetic and real field data sets can be found in Appendix. The results generated reservoir properties that were based on pressure and saturation change which revealed pressure depletion and oil recovery along with the correlations using the auxiliary equations.

7.1. Oil-in-Water Emulsions

The reservoir was put into production with initial pressure of 3000 psi without and with injection. The variation in pressure was observed for duration of 500 days with and interval of 100 days. The results show pressure depletion without injection and pressure buildup with injection. There after correlation with experiment on emulsion formation and water flooding test.

Figure 1. Pressure variation with distance without injection at \( t = 0 \) day and \( t = 100 \) days
Figure 2. Pressure variation with distance without injection at \( t = 200 \text{ days} \) and \( t = 300 \text{ days} \)

Figure 3. Pressure variation with distance without injection at \( t = 400 \text{ days} \) and \( t = 500 \text{ days} \)

7.2. Pressure Depletion without Injection

Figure (1-3) was the results of solution equations (18 and 20) without considering injection parameter \( (q_{wi}) \). This show the interactions of pressure variation and the response of reservoir surface distance in both direction \( (x) \) and \( (y) \) for predicting the pressure when oil-in-water emulsion was being swept towards the wellbore during production. Figure (1) shows the result at initial condition of 3,000 psi as specified by the boundary conditions. The effect of
starting with initial pressure of 3,000 psi was that no flow exists at this instance. This happen because water and oil were trapped within the porous and permeable formation. There was no change of pressure with respect to distance at initial stage of production. The pressure remains at 3,000 psi unless there was drilling operation that serves as an energy sink. Figure (1-3) shows the time when reservoir was put into production operation for 500 days. Note that these figures show that the pressure distribution was dropping everywhere in the reservoir at different specific number of days. At the beginning of Figure (1), initial pressure was very high and it started dropping as pressure drop increases.

Figure 4. Pressure variation with distance without injection at $t = 0 \text{ day}$ and $t = 100 \text{ days}$ with injection $q = 200 \text{ STB/day}$

Figure 5. Pressure variation with distance without injection at $t = 200 \text{ days}$ and $t = 300 \text{ day}$ with injection $q = 300 \text{ STB/day}$ to $400 \text{ STB/day}$
The pressure drops in Figure (1-3) were dropping in the sequence of 3,000 psi, 2,500 psi, 2,000 psi, 1,700 psi, 1,450 psi and 1,255 psi. It can be seen the pressure drop response was dominant within the reservoir. Production continues near wellbore and energy of the fluids in the reservoir was reducing until pressure drop approaching 1,220 psi. At this level, the energy of the reservoir has been depleted and production was declining steadily.

![Graph showing pressure variation with distance without injection at different time intervals](image)

**Figure 6.** Pressure variation with distance without injection at $t = 400$ days and $t = 500$ days with injection $q = 500 \text{ STB/day}$ to 600 \text{ STB/day}

### 7.3. Pressure Buildup with Injection

Figure (4-6) was the results of solution equation (18 and 20) with injection parameter ($q_{wi}$). This show the interactions of pressure variation and the response of reservoir surface distance in both direction ($x$) and ($y$) for predicting the pressure when oil-in-water emulsion was being swept towards the wellbore. During injection, the maximum pore may be 39.82% higher than the initial value as shown in Table 1. The pressure is higher than the initial value by over 10%. The purpose of injection is achieved and as injection proceeds, the compression stress will redistribute and the damage area enlarges. In this area, formation permeability jump up leading to pore pressure increased.

Figure (4) shows the result at initial condition of 3,000 psi as specified by the boundary conditions. The effect of starting with initial pressure of 3,000 psi was that no flow exists at this instance. This happen because water and oil were trapped within the porous and permeable formation. There was no change of pressure with respect to distance at initial stage of production. The pressure remains at 3,000 psi unless there was drilling operation that serves as an energy sink. Immediately water injection was introduced, the pressure change with respect to distance within the reservoir to 2,999.5 psi in Figure (4) and then began rise. This was the effects of initial water injection that shifted the initial pressure slightly and there after injection continue at selected location in the reservoir with specific injection rate for 500 days.

At this points, pressure within the reservoir began to build up everywhere in the reservoir as pressure increases in Figure (5-6) in this sequence 3,000 psi, 2,999.5 psi, 3,470 psi, 3,935 psi, 4,395 psi, 4,855 psi with injection rate. The effects of this pressure variation with distance
increases very fast around the wellbore as a result of injection. Oil production automatically increases with response to pressure change. With water injection, pressure increases and the force of water tends to stimulate the restrictions in the pore spaces and allowed for free flow path. This increases the recovery of oil that was remaining the reservoir, thereby improving oil recovery and also maintaining the flow rate over a long period.

**Figure 7.** Comparison of pressure variation with injection rate at $k_n$, $k_s$

**Figure 8.** Comparison of pressure variation with time at different viscosities $\mu$

**Figure 9.** Comparison of pressure variation with time at different injection rate $q$

**Figure 10.** Comparison of flow rate with time at different injection rate $q$
7.4. Pressure Variation with Modified Model Equations

The results generated from simulation of the new model solution equation (8 and 20) along the x-direction were examined on the following figures. Figure (7) show the relationship between the permeabilities $k_n$ and $k_s$ pressure variation and injection. These were relationship that exists as a result of water being injected into the formation to allow for oil-in-water emulsion flow. The two permeability increases with pressure as water injection increases. The plot of Figure (8) was the simulation profile to investigate pressure variation with time at different viscosities.

**Figure 11.** Comparisons of viscosities versus permeability and pressure for equation (18 and 20) with previous studies.

**Figure 12.** Rank Correlations between the New Model, Experiment and Civan, (1979).
This result revealed that at viscosity of 0.1cp, the pressure increases linearly with lower viscosity. When viscosity was 5cp, it shows that pressure has vertical increase and at certain point, pressure increases linearly. Figure (9) shows that pressure increases with time at different injection rate. The effect of injection on pressure was significant for oil-in-water emulsion flow as long as pressure increases astronomically. This also revealed the whole response of the plot which enhanced the recovery of oil. Figure (10) is the plot of flow rate with time at different injection rate. Figure (9) show that the plot enhances the recovery of oil from emulsion as injection rate increases and this corroborated the pressure build up in Figure (5-6). However, the results obtained so far significantly enhanced oil recovery.

![Figure 13. Rank Correlations between the New Model, Marseden, (1979); McAuliffe, (1973)](image)

7.5. Experiment for Emulsion Formation and the Correlations

Figure (11) shows the comparison of pressure variation $p$, permeabilities $k_n, k_s$ against viscosities $\mu$ for new model solution equation (18 and 20) and the experiment. This shows the pressure and permeability decreases as viscosity increases. Oil-in-water emulsion for both the new model and emulsion formation experiment are viscosity dependent and as a result, pressure drop exist in both domain. The viscosity of emulsion in Figure (11) is very significant for the fact that viscosity hindered normal permeability despite reduction in skin permeability and sweep efficiency is hindered. Figure (11) is the plot of pressure drop against viscosity for the comparison of the new model equation and emulsion formation experiment with some previous study on this concept. All pressure from these plots was pointing to increase in pressure drop as viscosity increases.

Figure (12-13) show the plot of correlation between experimental and new model which gave a value of $R^2 = 0.9952$. Figure (12) shows that Civan, (1979) and new model gave a correlation value of $R^2 = 9789$ and these indicated that there was a closed proximity between Civan, (1979) the new model. Figure (13) shows that Marseden, (1979) and the new model gave a correlation value of $R^2 = 0.9833$ and this has indicated a closed proximity but slight deviation exist when compared with Civan, (1979) and the new model. Figure (4.44) also shows
that McAuliffe, (1973) and the new model gave a correlation value of \( R^2 = 0.9707 \) and this indicated proximity between McAuliffe, (1973) and the new model but appeared the least proximity when compared with other plots in these correlations. Hence Figure (12-13) shows that variation exists when this work is compared with other previous studies. The rank correlation of the new model equation (18 and 20) and the experiment with other previous studies were perfectly correlated to unity.

**Table 1.** Flooding test results.

<table>
<thead>
<tr>
<th>Sand Pack Sample</th>
<th>Porosity</th>
<th>Permeability, k (Darcy)</th>
<th>Chemical slug for flooding</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>( k_w(S_w = 1) )</td>
<td>( K_0(S_{wi}) )</td>
<td>( K_w(S_{or}) )</td>
</tr>
<tr>
<td>Sample 1</td>
<td>39.82 %</td>
<td>0.33193</td>
<td>0.00189</td>
</tr>
<tr>
<td>Sample 2</td>
<td>37.72 %</td>
<td>0.37797</td>
<td>0.00238</td>
</tr>
<tr>
<td>Sample 3</td>
<td>37.72 %</td>
<td>0.37797</td>
<td>0.00237</td>
</tr>
<tr>
<td>Sample 4</td>
<td>39.62 %</td>
<td>0.33193</td>
<td>0.0257</td>
</tr>
</tbody>
</table>

**Figure 14.** Recovery Performance of Emulsion for 10\% Oil Flooding

**Figure 15.** Comparative Recovery Performance of Emulsion Flooding.
Table 2. Additional recovery on flooding test results.

<table>
<thead>
<tr>
<th>Recovery of oil after Water flooding at 95% Water cut (% OOIP)</th>
<th>Additional recovery (% OOIP)</th>
<th>Saturation % PV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>$S_{wi}$</td>
</tr>
<tr>
<td>49.6781</td>
<td>20.716</td>
<td>13.64</td>
</tr>
<tr>
<td>50.2945</td>
<td>20.846</td>
<td>14.04</td>
</tr>
<tr>
<td>51.5061</td>
<td>21.567</td>
<td>12.75</td>
</tr>
<tr>
<td>50.7423</td>
<td>22.144</td>
<td>14.73</td>
</tr>
</tbody>
</table>

7.6. Experiment for Flooding Test and the Correlations

The analysis of the flooding test experiment on emulsion stability and water flooding were conducted to serve as injection for the recovery of oil as seen on Table (1 and 2). Figure (14) shows the flooding process which involved interplay between water injection and emulsion injection at high pressure. The overall oil recovery by the flooding was dependent on the composition of injected emulsion, emulsion size, permeability of sand pack, viscosity of oil being displaced and porosity. Initially during water flooding, almost 50.56% of the oil was recovered in the first run of water flooding and water injected until water saturation reaches 90%. At this moment, we injected 0.5 pv emulsion slugs continue to inject water until the water saturation rose to 95% as shown in Figure (14). Water flooding experience water cut that reduces sharply and obviously declined, but accumulative oil recovery increases when the average porosity was larger than 37.72% with 5% pore volume injected for the four different samples. The cumulative average permeability of the formation test was about 33.37%. The effect of this recovery was that emulsion injection may not necessary leads to lower residual saturation. Table (2) show also the average oil recovery of about 50% at 95% water cut.

The presence of emulsion simply accelerates the oil recovery as seen in Figure (14) when water cut declined. Oil was recovered at different level of emulsions at 5%, 10%, 20%, and 30% respectively. This figure gave an early breakthrough flow of water which caused lower oil recovery. After water flooding experience water cut, additional oil recovery began to drain out of sand pack and measurement was taken at different sample with additional oil recovered. These curve compared the efficiency of the four samples with same pore volume injected (0.5% PV) of emulsion slugs. Water flooding test experiment performance was able to recover on average 50.56% oil with water flood and additional 21.56% oil was also recovered by emulsion slug injection at initial water, oil and residual oil saturation respectively. Table (1) contained four samples experiments carried out in sand pack with high porosity (39.82%) and permeability (33.19 - 37.72 mD).

Figure (15) Display a comparative production performance of oil recovery with different percentage of oil in emulsion. During the water flooding that swept the viscous oil, into the
lower permeability zone (Schneider, 2013). When zone of high permeability was flooded out, significant oil still remains in the lower permeability zone. With emulsion flooding, more oil was swept to the lower permeability zone of the sand pack. The emulsified oil that was retained in the high permeability zone reduced its permeability and when water flows, it increases the sweep efficiency and ultimately, mobility ratio was increase since emulsion is more viscous than the constituent oil as depicts in Figure (15). This shows that the sweep efficiency has been enhanced more significantly by flooding with emulsion rather than with water flooding. The whole cumulative oil recovery increases ultimately the sweep efficiency.

8. CONCLUSIONS

Near oil wellbore damages, specifically, oil-in-water emulsions has been simulated by formulating models involving modification of Darcy’s equation with cross section comparisons with experimental work in an attempt to optimize the reservoir pressure for improved oil recovery.

Based upon the model and the experiments, we conclude that the (THDPDE) model indicated pressure depletion over time without injection but increases under the influence of increased injection rate enhancing the oil recovery which corroborated with flooding process of enhanced oil recovery. Oil-in-water emulsions show that it follows pseudoplastic behavior. Dilute oil-in-water emulsions are shown to aid in the displacement of viscous oil by decreasing mobility of aqueous displacing phase and reducing interfacial tension between oil and water (Ajay Mandal et al., 2010).

The flooding behavior with water and emulsions were found to be identical. However, water flooding caused the pore to pressure increase and the influence area enlarges gradually and a little higher oil recovery was observed. Recovery efficiency is more than 22% of original oil in place over the conventional water flooding which may improve mobility ratio and increase sweep efficiency caused by injected water.

Current reservoir engineering practice allows for models modification of near wellbore flow compared with experimental work on well productivity to be called skin effects. Civan, (2007) introduced the skin factor to the flow equations representing this modification as a reduction in permeability in the vicinity of the wellbore. This state of the near wellbore zone alters the pressure gradient from the assumed homogeneous bulk reservoir properties. Contrarily, our experimental work shows that the most important criterion is the effective cross section comparisons with McAuliffe, (1973); Marseden, (1979); and Civan, (1979).

If this work is honored, cross section comparisons of model modifications with experimental in simulating the near wellbore damages should be embraced. The model predictions should be validated and those from experiments could then be made for near wellbore damages, and remedial treatments developed.

Acknowledgments

The authors would like to acknowledge the cooperation and support of the NNPC joint operators for the use of some classified information provided and the opportunity given for the experiments in the central research laboratory of Yaba College of Technology.
References


**Appendix**

![Figure A. Schematic of a rectangular reservoir with initial and boundary conditions](image)

\[
\frac{\partial P}{\partial x} \bigg|_{x=0} = 0 \quad P_{x=Lx} = P_L = 1000 \text{Psi} \\
\frac{\partial P}{\partial y} \bigg|_{y=0} = 0 \quad \frac{\partial P}{\partial y} \bigg|_{y=Ly} = 0
\]
**Table A.** Data set for the case study

<table>
<thead>
<tr>
<th>Parameter</th>
<th>FIELD</th>
<th>SI</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\phi$</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>$\mu$</td>
<td>0.33 cp</td>
<td>$3.3 \times 10^{-4}$ Pa.s</td>
</tr>
<tr>
<td>$c_t$</td>
<td>$1.0 \times 10^{-6} (kgf/cm^2)^{-1}$</td>
<td>$2.18 \times 10^{-9} Pa^{-1}$</td>
</tr>
<tr>
<td>$K$</td>
<td>1.5 mD</td>
<td>$1.48 \times 10^{-15} m^2$</td>
</tr>
<tr>
<td>$p_o$</td>
<td>400 psi</td>
<td>39.23 MPa</td>
</tr>
<tr>
<td>$S_{wi}$</td>
<td>18%</td>
<td>18%</td>
</tr>
<tr>
<td>$P$</td>
<td>1000 psi</td>
<td>98.07 MPa</td>
</tr>
<tr>
<td>Gaussian Noise</td>
<td>±10%</td>
<td>±10%</td>
</tr>
<tr>
<td>$a$</td>
<td>2,000 ft</td>
<td>609.6 m</td>
</tr>
<tr>
<td>$b$</td>
<td>2,000 ft</td>
<td>609.6 m</td>
</tr>
</tbody>
</table>