MODELING THE WETTABILITY ALTERATION TENDENCIES OF BIOPRODUCTS DURING MICROBIAL ENHANCED OIL RECOVERY

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Abstract

About 50-60% of the world's reservoirs are carbonate, and quite a significant number of them are naturally fractured and recoveries from these zones are significantly low. Some common EOR methods for production from these zones include thermal recovery, chemical processes (surfactant injection, caustic flooding etc.), miscible displacement etc. this study involves the modification of a generic model to facilitate the recovery of oil by the production of these biosurfactants and biogases. Since it is well established that increasing biosurfactant concentration causes a decreasing interfacial tension, it can be concluded that IFT decreases with time. a correlation of which is verified in this study. Models depicting the direct and indirect impacts of bioproducts on the wettability of a reservoir are presented. A drop in the IFT results in an instantaneous change in the wettability properties from either oil-wet or mixed wet condition to water wet.

Keywords: *Biosurfactants, Imbibition, Water-wet, Wettability*

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1. INTRODUCTION

Historically, all petroleum reservoirs are said to be strongly water-wet. This theory is based on the fact that all sedimentary reservoir rocks are created during sedimentary deposition in the presence of an aqueous phase [1]. Some research have studied the effects of surfactants on the wettability of a formation as it reverses the chemical charges associated with the native wetting state [2,3,4,5]. Rock wettability is highly dependent on the surface chemistry and the adsorption properties of the rock matrix, and primary chemicals used for these alterations are surfactants. For this study, biosurfactants are introduced. They are anionic, cationic, non-ionic or amphoteric and under right conditions, adsorb on the rock surface, attracting the desired phase so as to alter the rock wettability. This study is aimed at introducing the Microbial enhanced oil recovery technique to improve production by altering the wettability property of the fractured reservoir.

Fractured, mixed-wet formations usually have poor flooding performance because injected water tends to flow through the fractures and spontaneous imbibition into the matrix is not quite significant [6] and as such chemical surfactants are introduced for wettability alteration to increase water imbibition into the rock matrix. The primary purpose of these surfactants is to reduce ITF, displacing oil that proves difficult to be displaced by water alone.

The tendency of a fluid to adhere to a solid surface in the presence of other immiscible fluids is termed wettability Craig [7]. In an oil- water phase, wettability is the tendency for the rock to preferentially imbibe oil, water or both. If water-wet, the aqueous phase will be retained by capillary forces in smaller pores and on the walls of larger pores. Alternatively, the oleic phase will occupy the center of the pores. Nearly all geologic formations are completely saturated with water during their deposition and will strongly water-wet initially. During hydrocarbon migration into the water-saturated formation, the rock can either remain water wet or its wettability may change due to the hydrocarbon interaction depending on the stability of the wetting phase determined by pH, brine concentration and capillary pressure. Standnes and Austad [2] studied the effects of cationic and anionic surfactants on oil recovery by imbibition of water into oil-wet chalk cores. It was discovered that chalk was strongly oil-wet due to the adsorption of negatively charged oil components. Spontaneous imbibition of the cationic surfactant solution occurred rapidly due to the desorption of the adsorbed material by the formation. Once the adsorbed material was expelled, the rock was noticed to be water-wet, and imbibition occurred. Various authors have presented data on altered permeability of rocks using surfactants [3,4,8,9]. In similar studies, Hirasaki et al [5] and Adibhatia [9] experimented with the aim of altering the wettability of the Permian basin carbonate cores from Yates field from preferentially oil-wet to water-wet. This was achieved by the combination of IFT reduction by using sodium carbonate and surfactants.

2. MATERIALS AND METHODS

A generic model is modified to facilitate the recovery of oil by the production of these biosufactants. Materials for experimental studies were bacteria ($CH_{1.8}\ O_{0.5}\ N_{0.2}$) and nutrient sources such as glucose ($C_6\ H_{12}O_6$), and ammonium nitrate (NH_4NO_3). Metabolic products were acetate (CH_3COOH), carbon dioxide (CO_2) and nitrogen (N_2).

$$5C_6H_{12}O_6 + 8NO_3 \rightarrow 10CH_3COO^- + 10CO_2 + 4N_2 + 14H_2O + 2H^-$$

The mass balance for metabolite production is expressed above Zhang [10]. The empirical equation for cell growth and metabolism by consumption of both glucose (carbon sources) and ammonium (nitrogen sources) are expressed below.

$$C_6H_{12}O_6 + 1.2NH_4^- \rightarrow 6CH_{1.8}O_{0.5}N_{0.2} + 3H_2O$$

In this study, the principle of mass conservation is employed; stating that mass is not destroyed but conserved and transformation may be possible.

2.1 Material Balance Analysis

Consider the statement of mass balance given below:

$$[\text{rate of mass accumulation}] + [\text{rate of reaction of mass}] + [\text{rate of mass input}] = [\text{rate of mass output}] \quad (1)$$

But,

$$[\text{rate of mass accumulation}] = \frac{d(m_{bi}\,s)}{dt}$$

$$[\text{rate of mass reaction}] = 0$$

$$[\text{rate of mass input}] = \varphi\tau_i$$

$$[\text{rate of mass output}] = \varphi t$$

Therefore,

$$\frac{d(m_{bi}\,s)}{dt} + 0 + \varphi\tau_i = \varphi t \quad (2)$$

$$m_{bi}\frac{ds}{dt} = \varphi(t - \tau_i) \quad (3)$$

Water variation in every block is given by Barenblatt et al [11] equation above. Considering the reservoir as a whole [not discretized] we have:

$$m_{bi}\frac{ds}{dt} - \varphi(t) = 0 \quad (4)$$

Determining the imbibition rate, recall the semi-empirical law:

$$\varphi(t - \tau_i) = \frac{\alpha\exp\left(-\beta\left((t-\tau_i)\right)\right)}{\sqrt{\beta\left((t-\tau_i)\right)}} \quad (5)$$

Considering the whole reservoir, the above reduces to:

$$\varphi(t) = \frac{\alpha\exp\left(-\beta\left((t)\right)\right)}{\sqrt{\beta\left((t)\right)}} \quad (6)$$

Where

$$\beta = \frac{36\sigma\cos\theta}{l^2\mu_o}\sqrt{\frac{k_{res}}{m_{res}}}$$

And

$$\alpha = m_{res}\, l^3\frac{\eta_o s_o^0\beta}{\sqrt{\pi}}$$

From material balance, substituting the above into Equation (6):

$$\varphi(t) = \frac{\left(m_{res}\, l^3\frac{\eta_o s_o^0\beta}{\sqrt{\pi}}\right)\exp\left(-\frac{36\sigma\cos\theta}{l^2\mu_o}\sqrt{\frac{k_{res}}{m_{res}}}\right)(t)}{\sqrt{\frac{36\sigma\cos\theta}{l^2\mu_o}\sqrt{\frac{k_{res}}{m_{res}}}(t)}} \quad (7)$$

Assuming that microbes are in suspension in water and are smaller in size than the porous media, recall Venkata et al [12] equation for microbial growth:

$$\frac{dN}{dt} = nN\left(1 - {}^{N}\!/_{N_{max}}\right) \quad (8)$$

Solution for the above using initial conditions $(N(t = 0) = N0$,

$$N(t) = \frac{N_o\exp(nt)}{1 - \frac{N_o}{N_{max}}(1 - \exp(nt))} \quad (9)$$

Combining molasses consumption with growth and production of metabolites (biogases and biosurfactants), from mass balance equation, we have:

$$M_{mol} = M_o + \frac{N_{max} - N_o}{m}M(t) \quad (10)$$

$$M_o = -\frac{N_{max} - N_o}{m_o}M(t) \quad (11)$$

$$M_s = -\frac{N_{max} - N_o}{m_s}M(t) \quad (12)$$

Where

$$M(t) = \frac{1 - \exp(nt)}{{}^{N_o}\!/_{N_{max}} - (1 - \exp(nt))} \quad (13)$$

Considering biosurfactant as a wetting phase and substituting Equation (13) in Equation (12), we have:

$$M_s = -\frac{N_{max} - N_o}{m_s}\left(\frac{1 - \exp(nt)}{\frac{N_o}{N_{max}} - (1 - \exp(nt))}\right) \quad (14)$$

Let

$$-\frac{N_{max}-N_o}{m_s}=Y$$

And

$$\frac{N_o}{N_{max}}=Z$$

We have:

$$M_s=Y\left(\frac{1-\exp(nt)}{Z-(1-\exp(nt))}\right) \quad (15)$$

Also, for carbonic gases, we have:

$$M_c=Y_1\left(\frac{1-\exp(nt)}{Z_1-(1-\exp(nt))}\right) \quad (16)$$

But for Equation (14), (15) and (16),

$$\exp(nt)=1+(nt)+\frac{(nt)^2}{2!}+\frac{(nt)^3}{3!} \quad (17)$$

$$M(t)=\frac{-nt-\frac{(nt)^2}{2!}-\frac{(nt)^3}{3!}}{Z++(nt)+\frac{(nt)^2}{2!}+\frac{(nt)^3}{3!}} \quad (18)$$

$$M_s=\frac{Ynt+Yn^2\left(\frac{t^2}{2}\right)+Yn^3\left(\frac{t^3}{6}\right)}{Z++(nt)+\frac{n^2t^2}{2}+n^3\left(\frac{t^3}{6}\right)} \quad (19)$$

$$M_c=\frac{Y_1nt+Y_1n^2\left(\frac{t^2}{2}\right)+Y_1n^3\left(\frac{t^3}{6}\right)}{Z++(nt)+\frac{n^2t^2}{2}+n^3\left(\frac{t^3}{6}\right)} \quad (20)$$

Using the Maclaurin's series to obtain the solution to the above equations,

$$M_{c(s)}=f(t)=f(0)=tf'(0)+\frac{t^2}{2!}f''(0)+\frac{t^3}{3!}f'''(0)+\ldots \quad (21)$$

$$f(0)=0$$

$$f'(0)=\frac{Yn}{Z}$$

$$f''(0)=\frac{Yn^2(Z-1)}{Z^2}$$

Therefore,

$$M_c=\frac{Y_1n^2(Z_1-1)}{2{Z_1}^2}t^2+\frac{Y_1n}{Z_1}t+\varepsilon \quad (22)$$

$$M_s=\frac{Yn^2(Z-1)}{2Z^2}t^2+\frac{Yn}{Z}t+\varepsilon \quad (23)$$

3. RESULTS AND DISCUSSION

Table -1: Parameters to be used in model

Parameters	Values
Injection rate	10days
Reservoir porosity	20%
Average linear block lengths	10m
Oil displacement coefficient	6%
Initial oil saturation	60%
IFT coefficient	40Nm/m
Wettability angle	50
Oil viscosity	40pa.sec
Reservoir permeability	$0.2/\mu m^2$
m_s	4.4
m_c	2.3
Timt t,	0, 50, 100, 150, 200, 250, 300 hrs

3.1 Calculations

Case 1

Recalling Equation (7),

$$\varphi(t)=\frac{\left(m_{res}l^3\frac{\eta_o s_o^0\beta}{\sqrt{\pi}}\right)exp\left(-\frac{36\sigma cos\theta}{l^2\mu_o}\sqrt{\frac{k_{res}}{m_{res}}}\right)(t)}{\sqrt{\frac{36\sigma cos\theta}{l^2\mu_o}\sqrt{\frac{k_{res}}{m_{res}}}(t)}}$$

Substitution of the values from Table 1 into the equation above gives the result tabulated below.

Table -2: Change in Imbibition with time

$\varphi(t)$ (cu m/sec)	$t(hrs)$
0	0
2.745	50
0.6110	100
0.1568	150
0.0427	200
0.0120	250
0.0035	300

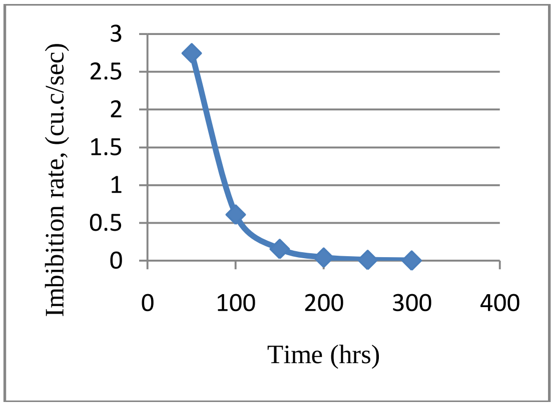

Fig -1: Plot of imbibition with time

The figure above shows the decrease in imbibition with increasing time.

Case 2

Biosurfactant concentration, assuming $n=3.25\times10^{-5}$, $N_{max}=0.245$ and $N_o=0.004$.

Using Equation (23),

$$M_s = \frac{Yn^2(Z-1)}{2Z^2}t^2 + \frac{Yn^2}{Z}t + \varepsilon\ ,$$

$$N_o/N_{max} = Z$$

And

$$Y = -\frac{N_{max} - N_o}{m_s}$$

$Y=-0.0554$

$Z=0.00163$

$Z^2 = 0.000267$

$\frac{Yn^2(Z-1)}{2Z^2} = 0.000011$

$\frac{Yn}{Z} = 0.0011$

$$M_s = 0.000011t^2 + 0.00111\ t + 0.0536 \qquad (24)$$

Note that ε is evaluated during the Maclaurin's series expansion

Equation (24) can be used to generate M_s values for t= 0, 50, 100, 150, 200, 250, 300 hours.
The table below shows values of M_s at different times, t after applying the above equation.

Table -3: Values of biosufactant concentration at various time levels

M_s	Time t (hrs)
0.0536	0
0.0256	50
0.0526	100
0.1346	150
0.2716	200
0.4636	250
0.7106	300

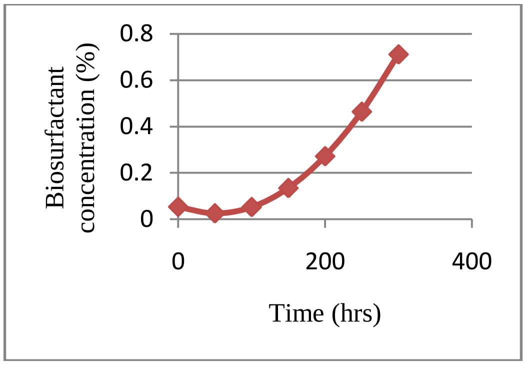

Fig -2: Plot showing the increase of biosurfactant concentration with time

Case 3

Recalling Equation (22) for biogas concentration, M_c, where $m_c = 2.3$

$$M_c = \frac{Y_1n^2(Z_1-1)}{2{Z_1}^2}t^2 + \frac{Y_1n}{Z_1}t + \varepsilon$$

$Y_1 = \frac{-N_{max}\ -N_o}{m_s} = -0.1066$

$Z=z_1$, and $Z^2 = Z_1^{22}$

$\frac{Y_1n^2(Z_1-1)}{2{Z_1}^2} = 2.11\ \times 10^{-5}$

$\frac{Y_1n}{Z_1} = -0.00213$

$M_c = 2.11\ \times\ 10^{-5}t^2 - 0.00213t + 0.0536 \qquad (25)$

The results of the computations are displayed in the table below.

Table -4: Values of carbonic biogas concentration at various time levels

M_s	Time t (hrs)
0.0536	0
0.0001	50
0.0516	100
0.2089	150
0.4716	200
0.8399	250
1.3130	300

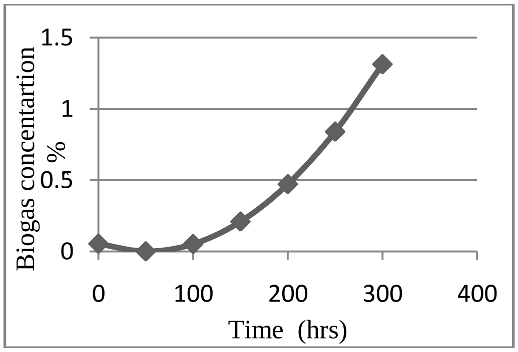

Fig -3: Plot showing the increase of carbonic gas concentration with time

3.2 Discussion

From Figures 2 and 3, it is shown that the concentration of the produced biosurfactants and carbonic gases (biogases) increased with time after calculations. The interfacial tension decreases with increasing surfactants concentration [13]. Since Figure 2 represents an increasing concentration of biosurfactants responsible for IFT reduction, the Model correlates with Sitnikov’s model [13].

4. CONCLUSIONS

The deduced model studies the effects of increasing concentration of bioproducts with time and its relative effects on interfacial tension. Since it is well established that increasing biosurfactant concentration causes a decreasing interfacial tension, it can be concluded from Figure 2 that ITF decreases with time. Once there is a drop in the IFT, wettability properties changes instantly causing a preferential phase usually water to be imbibed.

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NOMENCLATURE

m_{res} = formation porosity %
s = saturation
t= time
l= average specific linear block size
k=permeability coefficient of a block
$\varphi(t)$ = imbibition rate
σ = interfacial tension coefficent
θ = wettability angle
μ_o = oil vicosity
η_o = oil displacement coefficient
N= biomass concentration
n = specific biomass growth rate.
M_s = biosurfactant concentration
M_c = carbonic gas concentration
M_{mol} = molasses concentration
$m_{c=}$specific gas production coefficient
m_s = specific biosurfactant concentration coefficient
m = mass coefficent of mollases consumption