THE EFFECT OF WATER SALINITY ON PERMEABILITY OF OIL RESERVOIR

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Abstract

The recovery of oil from clay-sandstone as revealed by past studies can be improved by increasing the concentration of the salinity in the core. This is as a result of the sensitivity of the clay-sandstone to the water salinity. Conversely, there is no established model to predict the permeability of core for a given concentration of brine and the value of concentration for optimum oil recovery. Data from experiment on clay content sandstone from different cores in Berea were analyzed and permeability was found as a function of concentration of brine as $k = 1759.063\ln\alpha - 4864.5$ From the model for the variation of permeability of natural clay-sandstone as a function of brine concentration, 12179.79 kgm^{-3} concentration of brine will give equivalent permeability of the natural core filled with air, in comparison with possible maximum permeability of the reservoir for optimum oil recovery.

Keywords

Reservoir; brine; concentration; permeability and salinity

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1. Introduction

Permeability is one of the fundamental properties of every oil reservoir rock. The oil in a reservoir can be extracted through core only if the rock is permeable, that is to say if the pores are interconnected. The amount and type of clay has a great influence on the permeability, especially if the flowing substance reacts with clay. When using fresh water, clay which contains mortmorillonite may considerably swell and block the pores. Besides that, the salt content and the hydrogen – ion concentration (pH) of water has some influence [1,6].

Water sensitivity attributable to clay swelling in a sandstone is responsible for formation of damage mechanics vis-à-vis reduction of permeability of reservoir [4,5,9,12]. [1] were among the first to investigate and report large decreases in permeability of clay-containing sandstone with decreasing salinity of the pore water. [11], two research workers in Germany, reported similar observations. They later extended their work to include the effects of polar and non polar solvents under varying pressure gradients.

In this work, the detailed study of the flood test used by [7] will not be discussed, but the data obtained from the flood test on the twenty different cores (or reservoir) will be analyzed for modeling the relationship between the concentration of the brine (or salinity)and the permeability of the core. Also, there is existence of a critical concentration that gives a maximum permeability of the core that produces optimum oil recovery from natural core filled with clay. This concentration will be determined with the model of permeability as a function of core water salinity [6].

2. Theoretical Background

The migration of small solid materials ('fines') within porous media has long been recognized as a source of potentially severe permeability impairment in reservoirs. This impairment has a strong effect on the flow capability (relative permeability) of the reservoir rock. Fines migration occurs when loosely attached particles are mobilized by fluid drag forces caused by the motion of fluid within the pore space. One of the primary factors that determine the migration of clay particles is the brine composition. Laboratory studies have shown that brine salinity, composition and pH can have a large effect on the microscopic displacement efficiency of oil recovery by water flooding and imbibitions. Several experiments have shown that injection of brine can improve oil recovery from nature core (or reservoir). This is possible because increase in salinity of water in core pores increases permeability of the core and this, increase oil recovery. Data from experiment on Berea cores by [7] show that oil recovery via imbibitions increase significantly with increasing salinity of connate brine.

[8], in their study of permeability damage via fines migration in extracted core material, concluded that permeability and oil recovery were nearly independent of brine composition. Contrarily, other experimental studies, suggested that changes in brine composition could have a large effect on oil recovery. [10] proposed that additional oil recovery is the consequence of clay/clay interaction weakening in the porous medium [especially kaolinite] when low salinity brine is injected. They consider that the expansion of clay layers leads to detachment from the rock surface of mixed-wet clay particles that are able to transport adsorbed oil droplets. This mechanism suggests a permeability reduction due to pore constrictions and/or fines production and evolution to a more water wet system.

Oil deposits do not only contain oil, salt water, and often also free gas, is always present, too. Consequently, there are within the porous rocks at least two, possibly even three, not into one another soluble phase, each of them influencing the flow capacity of the other. The permeability for each phase is called the effective permeability. It is quite obvious that the effective permeability is no mere rock property any longer. It is affected not only by the rock, but also by the quantitative proportion of phases in the rock pores [1].

2.1 Darcy's Law

In other to get a quantitative information on the permeability of sands to water, [3] carried out some experimental investigations which resulted in the famous Darcy law (1). Darcy's law is used in the oil industry in various forms for numerical statements about the permeability of oil reservoir rocks.

Darcy's law for homogenous fluids generalized reads

$$v_s = -K/\eta\,(\partial p/\partial s - \gamma.g.\cos\theta)$$

1

When

v_s = rate of flow (through the unit of area) in the direction s.

θ = angle between the line of the vertical and the direction of flow s.

η = viscosity of fluid

γ = density of fluid.

g = acceleration of gravity

p = pressure of fluid.

Equation 1 stands for steady-state as well as non steady-state flows through a porous medium. Generally all variables of equation 1 are different for each point of the rock, also γ provided that the fluid is compressible.

In the general Equation 1, the factor K represents the coefficient of permeability. If the porous medium is not homogenous, K also changes point to point. Equation 1is generally uses to determine the mean coefficient of permeability for special textures of rocks. K is then considered a constant and called permeability.

2.2 Steady-State flow of a homogeneous medium

The numerical solution of a measurement of permeability like this is done with the help of Darcy's law. From equation 1, the following equation for the linear flow of a gas with the viscosity, through a core with the constant cross section A and the length L can be derived by integration, if the gravity is neglected:

$$\frac{V_o}{t} = \frac{K}{\eta} \cdot \frac{A}{L} \cdot (p_1 - p_2).pm$$

2

From that follows for the coefficient of permeability K, generally called the permeability.

$$k = \frac{V_o}{t} = \frac{K}{\eta} \cdot \frac{A}{L} \cdot (p_1 - p_2).pm$$

3

Where V is the air volume passed through the core in the time t, referred to 0^0C and 760mm mercury, and pm is the mean pressure. If the permeability is measured with the help of an incompressible fluid instead of air, we get the following equation:

$$K = \frac{V}{t} \cdot \eta \cdot \frac{l}{A} \cdot \frac{1}{p_1 - p_2}$$

4

As far as we give V in cubic centimeters, t is seconds, in centipoises, L in centimeters, A in square centimeters, p_1 and p_2 in atmospheres, we get the permeability in darcy. As the permeability of oil reservoir rocks generally is only a fraction of a darcy, we work with millidarcies (1darcy =1000 millidarcies)

2.3 Reservoir Heterogeneity and Stratification

Stratification and heterogeneities strongly influence the oil recovery process. Reservoirs with higher vertical permeability are influenced by cross flow perpendicular to the bulk flow direction. Viscous, capillary, gravity and dispersive forces generally influence this phenomenon. Cross-flow may influence to increase the vertical sweep, but generally the effects are detrimental to oil recovery due to the gravity segregation and decreased flow velocity in the reservoir. This leads to reduced frontal advancement in lower permeability layer. Water alternating-gas recoveries and continuous gas injections are more strongly affected by these phenomena. Reservoir heterogeneity controls the injection and sweep patterns in the flood. The reservoir simulation studies for various k_v/k_h (vertical to horizontal permeability) ratios suggest that higher ratios adversely affect oil recovery in water alternating-gas process.

It has been observed that the vertical conformance of water alternating-gas displacements is strongly influenced by conformance between zones. In a non-communicating-layered system, vertical distribution of CO_2 is dominated by permeability contrasts. Flow into each layer is essentially proportional to the fractional permeability of the overall system (average permeability * layer thickness (k*h)) and is independent of water alternating-gas ratio, although the tendency for CO_2 to enter the high permeability zone with increasing water alternating-gas ratio cannot be avoided. Due to the cyclic nature of the water alternating-gas, the most permeable layer has the highest fluid contribution, but as water is injected it quickly displaces the highly mobile CO_2 and all the layers attain an effective mobility nearly equal to the initial value. These cause severe injection and profile control problems. The higher permeability layer(s) always respond first. Water alternating-gas will reduce mobility not only in the high permeability layer but also in the low permeability layer, resulting in a larger amount of the CO_2 invading in the highest permeability layer.

The ratio of viscous to gravity forces is the prime variable for determining the efficiency of water alternating-gas injection process and controls vertical conformance of the flood. Cross-flow or convective mixing can substantially increase reservoir sweep even in the presence of low vertical to horizontal permeability ratios. Heterogeneous stratification causes physical dispersion, reduces channeling of CO_2 through the high permeability layer, and delays breakthrough. This is attributed to permeability and mobility ratio contrasts. This is unfavorable and greatly influences the performance of the flood. However, the effects are reservoir specific and the overall effect is dependent on various parameters like permeability, porosity, reservoir pressure, capillary pressure and mobility ratio [2].

3. Material and Method

By using the core flood tests, water sensitivity of sandstones cores were determined by first measuring permeability to air, then to a concentrated artificial brine (or formation brine), and finally to successively more dilute brines, eventually ending

with fresh water. The concentration of the brine used ranges from 100-1000 g/gal. In some cases switching directly from concentrated brine to fresh water was used as a test for water sensitivity. Twenty different sandstone cores with clay content located at Berea which was subjected to the above experiment by Johnston and Beeson and the data is presented in table 1. Berea sandstone is known to be water sensitive, contained barely a trace of swelling clay. The permeability was measured in millidarcy (md) while the concentration was measured in gramme/gallon (g/gal). These units are converted to S.I. units for better understanding and clarity.

Conversion of units to S.I units

1US gallon $= 0.003785$ m^3

1000g $\quad = 1$kg

Therefore 1g/gal $= 0.264172052$ kgm^{-3}

1 darcy $= 1$millidarcy (md)

3.1 Determination of the relationship between core permeability and brine concentration

In order to determine the pattern of the relationship between the two variables (permeability and concentration), plot of the mean of the permeability of the core for each concentration versus concentration of the brine was prepared. The equation of the graph is the model to determine the permeability of the exploitable oil reservoir as a function of concentration (or salinity) of water.

3.2 Determination of the 'critical concentration' for optimum oil recovery

The critical concentration which could give a maximum permeability for optimum oil recovery was obtained by interpolating the mean permeability of the air, which is characterized with maximum permeability with already established model. This is done because clay content reservoir filled with air only always has higher permeability than clay content reservoir filled with either brine or fresh water.

4. Result and Discussion

Permeability varies with type of flowing medium. This is true because proportionality constant of Darcy's law, the permeability is only possible for a particular type of the flowing medium. Thus, permeability depends on the type of the flowing medium. For a particular reservoir (or pores), there will be great differences in the permeability if we use not only air, but salt of various concentration or fresh water. When fresh water flows in a reservoir with clay content, certain clay has the ability to exchange ions or swell up and thereby reduces the permeability. However, the pH- value of water solution which is the function of its salt concentration has great effect on the clay action, vis-a-vis the permeability of the oil reservoir. The ability of the clay content to swell up in the reservoir is usually higher to fresh water than to salt water ones. The permeability changes of oil reservoir with water of various concentrations are very important in oil recovery. At the use of fresh water, the permeability decreases to very small values. However, if the salt water of required concentration is used, the clay particle does not get mobilized or swell up and thereby not be able to fill the pores of the reservoir.

It is obvious from [7] and Table 1 that the permeability (measured in millidarcy) increases with increasing salt water concentration (measured in g/gal). However, there is a need to establish a model between permeability of the oil reservoir and the concentration of the salt water in order to determine permeability of reservoir with clay content with a known concentration of salt water. Also, the 'critical concentration' which could give maximum permeability for optimum oil recovery will be determined with this model.

Table 1: Effect of Water Salinity on Permeability of Natural Cores [7]

Field	Zone	K_a	$K_{1,000}$	K_{500}	K_{300}	K_{200}	K_{100}	k_w
S	34	4,080	1,445	1,380	1,290	1,190	885	17.2
S	34	24,800	11,800	10,600	10,000	9,000	7,400	147
S	34	40,100	23,000	18,600	15,300	13,800	8,200	270
S	34	39,700	20,400	17,600	17,300	17,100	14,300	1,680
S	34	12,000	5,450	4,550	4,600	4,510	3,280	167
S	34	4,850	1,910	1,430	925	736	326	5.9
S	34	22,800	13,600	6,150	4,010	3,490	1,970	19.5
S	34	34,800	23,600	7,800	5,460	5,220	3,860	9.9
S	34	27,000	21,000	15,400	13,100	12,900	10,900	1,030
S	34	12,500	4,750	2,800	1,680	973	157	2.4

S	34	13,600	5,160	4,640	4,200	4,150	2,790	197
S	34	7,640	1,788	1,840	2,010	2,540	2,020	119
S	34	11,100	4,250	2,520	1,500	866	180	6.2
S	34	6,500	2,380	2,080	1,585	1,230	794	4.1
T	36	2,630	2,180	2,140	2,080	2,150	2,010	1,960
T	36	3,340	2,820	2,730	2,700	2,690	2,490	2,460
T	36	2,640	2,040	1,920	1,860	1,860	1,860	1,550
T	36	3,360	2,500	2,400	2,340	2,340	2,280	2,060
T	36	4,020	3,180	2,900	2,860	2,820	2,650	2,460
T	36	3,090	2,080	1,900	1,750	1,630	1,490	1,040

NOTE: K_a means permeability to air, K_{500} means permeability to 500gr/gal. Cl solution K_w means permeability to fresh water

Figure 1 shows the pictorial representation of the variation of permeability of cores with concentration ranging from 100 – 1000 g/gal. It shows that almost all the core permeabilities fall below 5000 md, which is far above 100 md, that is refers to as seal reservoir. However, few cores are found to be above 5000 md. Looking at the last column of the Table 1, some cores filled with fresh water have permeabilities that fall below 100 md. These cores are seal reservoirs, which are not exploitable because their pores are not permeable.
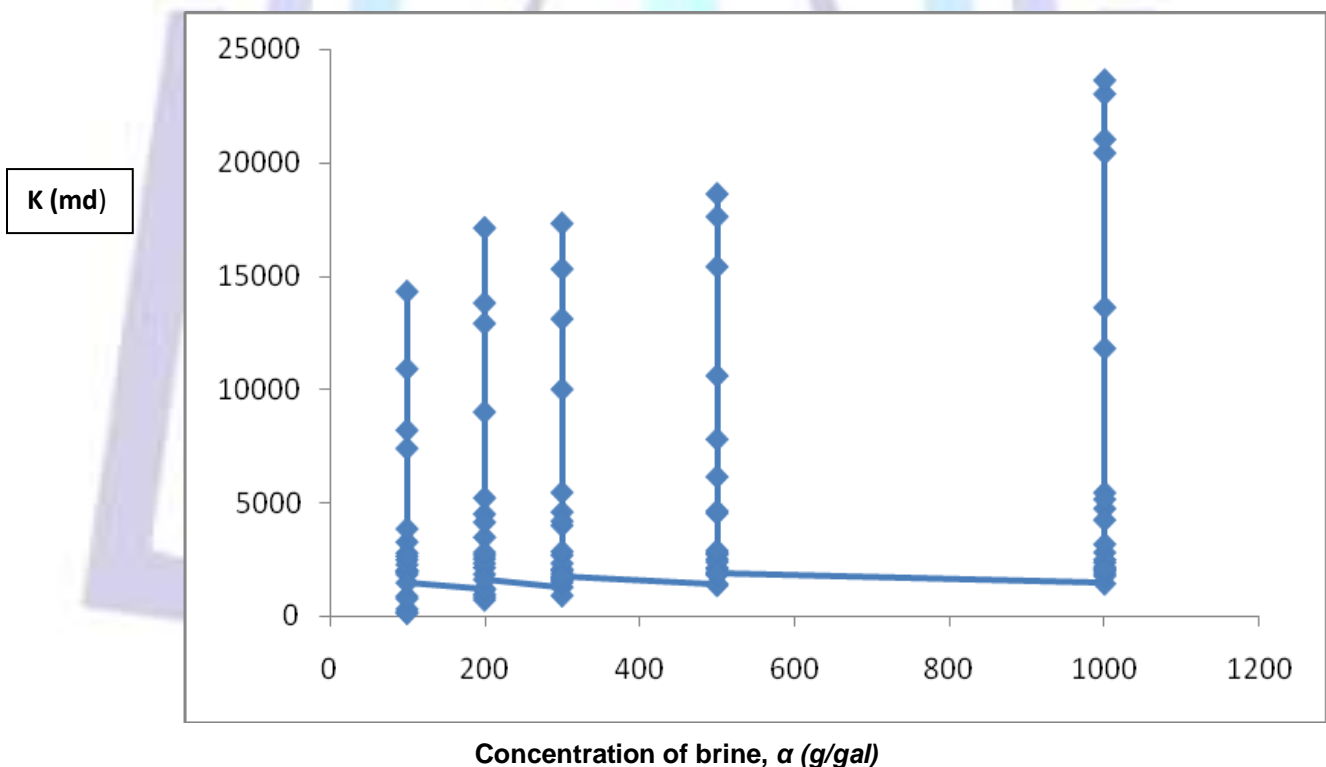

K (md)

Concentration of brine, *α (g/gal)*

Fig.1: Variation of Permeability with Concentration of brine

It is established from the plot of permeability mean of core for a particular concentration (table 2) versus concentration of brine that permeability increases with concentration in logarithm form, with equation *k= 1759.063 ln(α) -4864.5* (Fig. 2) .With this established model, one can then determine the critical concentration of the brine to obtain optimum oil recovery. This can be done by interpolating the permeability mean of cores filled with air with the model, and the concentration obtained is 46105.50 g/gal, which is equivalent to 12179.79 kgm^{-3} in S.I. units. This implies that the highest degree of concentration of brine that can be compared with the permeability of air is12179.79 kgm^{-3}. From the existing data, the concentration of brine should be as high as 12179.79 kgm^{-3} in order to obtain the permeability of the natural core filled with air. This concentration could then be taken as the expected concentration of brine to obtain optimum oil recovery in clay content sandstone core filled with brine.

Table 2: Concentration of brine and the mean of permeability

Concentration (g/gal)	Concentration (Kgm^{-3})	Permeability mean (md)
100	26.417	3492.10
200	52.834	4559.75
300	79.251	4827.50
500	132.085	5569.00
1000	264.170	7766.65

$$k = 1759.\ln(\alpha) - 4864.$$
$$R^2 = 0.934$$

K(md))

Concentration of brine, α (g/gal)
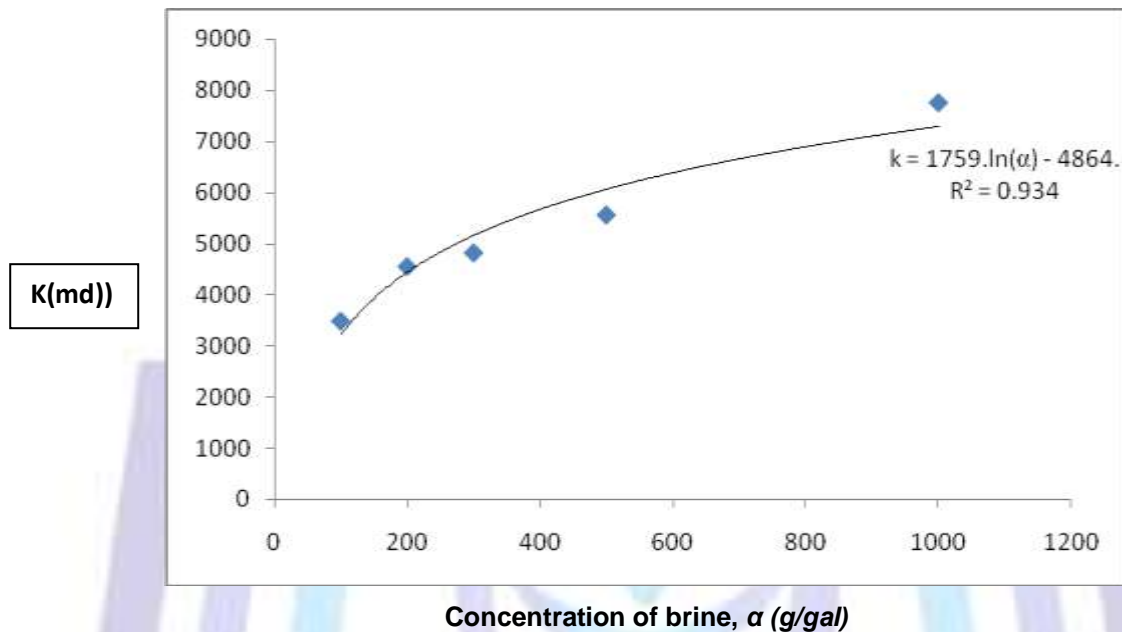
Fig 2: Plot of mean permeability versus concentration of brine

The degree of damage of the reservoir (or core) by montmorillonite clay present is widely recognized problem by oil industry and there is a strong correlation between clay content reservoir permeability and water salinity. The possibility of reducing clay migration and swelling to negligible amount in the sandstone oil reservoir can be achieved with the brine concentration of 12179.79 kgm^{-3} .

5. Conclusion

Data from the previous experiment conducted on Berea cores by Johnston and Beeson show that oil recovery via imbibitions increase significantly with increasing concentration brine. However, there is no an established model to predict the permeability of core for a given concentration of brine. Also, the value of concentration that gives possible maximum permeability for optimum oil recovery has not been determined. In this work, the equation of the plot of permeability versus concentration of brine was found to be $k = 1759.063 \ln \alpha - 4864.5$.

From the model for the variation of permeability of natural clay-sandstone as a function of brine concentration, 12179.79 kgm^{-3} concentration of brine will give equivalent permeability of the natural core filled with air, vis-à-vis possible maximum permeability of the reservoir for optimum oil recovery.

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