

Permeability Restoration of Saudi Arabia rocks

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ABSTRACT

During completion operation, filtrate and colloidal particles present in the completion fluids may alter and reduce the reservoir production. Laboratory tests were conducted to study the formation damage potential of high-density brine completion fluids for various sandstone core samples. The results obtain that both amount and type of clay content have strong effect on permeability restoration. For dirty sandstone formation, permeability restoration caused by addition ZnBr₂ is more than that by addition surfactant; however for clean sandstone formation permeability restoration caused by addition surfactant is more than that by addition ZnBr₂.

Keywords: Permeability, Restoration, Surfactant.

INTRODUCTION

The residues of completion fluids in a near-well bore environment substantially can reduce the hydrocarbon conductivity of reservoir by the following [1-7].

1. Interaction between filtrate and the fine solids within the pore network of the formation, this may result in swelling and/or dispersion of clay mineral.
2. Interaction between filtrate and the formation rock, if the filtrate contains strong wetting component, the formation wettability may be reversed to oil wet.
3. Interaction between filtrate and the formation fluids, the filtrate from oil base fluid can emulsify the connate water in the formation. This may result in an *in-situ*-emulsion blockage, which will reduce the mobility to oil. The filtrate from water base fluid can cause plugging of pore throat due to scaling or precipitation of solid crystals if the filtrate is not compatible with the formation fluid.
4. Physical blocking of pores openings in the wellbore region Invasion of colloidal particles from fluids that are not flushed out when the well is put on the production will reduce the permeability of the formation.

Depending on the fluids used while completion operation, the rock type and its original flow properties, any of the above mechanisms or their combination may lead to formation damage. Many investigators have studied these mechanisms. Their research has been concentrated on individual components and their interaction on flow properties of rock or on design of a fluid composition to stabilize a clay sensitive formation. If the formation damage is easily removed, in this case a fluid is permeability restoration. Due to the exponential growth of horizontal wells in recent years, the permeability restoration issue attains more consideration. Formation damage can occur at any time during a well's life [8-12]. The existence or absence of a damaged zone surrounding the wellbore is normally confirmed by performing pressure tests in the well, e.g. pressure build-up test. These tests providing a dimensionless number (skin factor), whose algebraic value indicates the severity of the formation damage. The formation damage caused by high-density brine completion fluids had been studied by some investigators [2-4]. They concluded that the minimum formation damage achieved by addition of ZnBr₂ or by addition of surfactants. In this research, laboratory tests were

conducted to study the formation damage potential of high-density brine completion fluids formulated with $ZnBr_2$ or a surfactant for various sandstone core samples, to clarify their effect on the sandstone rocks, and to know which mechanism the best is for each rock samples.

MATERIALS AND METHODS

Experimental study involves essentially experimental set up as the liquid permeameter assembly, for measuring the oil permeability before and after damaging the core sample. The core sample is full saturated with brine, flooded with crude oil at high flow rate to reach connate water saturation (S_{wi}). Then the initial oil permeability (K_{oi}) was measured. Two pore volume of completion fluid was injected in core sample at opposite direction. After the completion fluid invasion into core sample, crude oil was then injected by outlet face of the core. After many pore volumes of oil injected, oil permeability (K_o) was calculated.

Damage ratio

Damage ratio (DR) is define as the percentage of the original permeability lost after the invasion of completion fluid into the core sample. $DR = (1 - K_o/K_{oi})$.

Permeability restoration

Permeability restoration by an agent is expressed as the difference between the damage ratio caused by completion fluid without any agent and that with an agent.

RESULTS AND DISCUSSION

Sandstone fresh cores were obtained from producing areas. Berea sandstone cores were also used because of their universally acquired position in petroleum research. The mineralogical analyses of the cores and relative abundance of clay minerals were carried out by computerized X-ray diffraction. The results are reported in Tables 1 and 2.

Effect of $ZnBr_2$

The results show the effect of zinc bromide ($ZnBr_2$) on the pH value of 14.2 ppg calcium bromide ($CaBr_2$) completion fluid. We observed that, high concentration calcium bromide is neutral to slightly alkaline, but zinc ion is acidic. To study the effect of high-density brine completion fluids formulated with $ZnBr_2$ on permeability restoration for various formations, same experimental have been carried out using Berea, Aramco-1, Aramco-2 and Khafji sandstone core samples as formations different in both amount and type of clay, and 14.2 ppg $CaBr_2$ brine without any additive and 14.2 ppg $CaBr_2$ brine formulated with 8% $ZnBr_2$ as completion fluids. (Figures 1-4) show the results obtained in this regard. Figure 1 shows that, the damage ratio of Berea sandstone core sample decreases with increasing oil pore volumes injected when about 5 pore volumes were injected, after that damage ratio was constant. Minimum damage ratio of Berea sandstone core sample is 22.6% after back-flushing the contaminated 14.2 ppg $CaBr_2$ brine without any

Table 1: Mineralogical analysis of cores.

Core Type Composition (%)	Berea sandstone	Aramco-1 sandstone	Aramco-1 sandstone	Khafji sandstone
Quartz	75	92.7	88.4	78.3
Feldspars	10	3.8	4.3	8.6
Clays	10	3.5	7.3	13.1
Dolomite	5	-	-	-

Table 2: Relative abundance of clay minerals in the cores.

Core Type Composition (%)	Berea sandstone	Aramco-1 sandstone	Aramco-2 sandstone	Khafji sandstone
Kaolinite	63	56	61	48
Chlorite	12	44	31	29
Illite	25	-	6	15
Montmorillonite	-	-	2	8

agent, and it is 4.8% after back-flushing the contaminated 14.2 ppg CaBr₂ brine formulated with 8% ZnBr₂. Figures 2-4 obtain that the minimum damage ratio of Aramco--1, Aramco--2 and Khafji sandstone samples after back-flushing the contaminated 14.2 ppg CaBr₂ brine without any agent are 18.9%, 27.1% and 33.8% respectively and they are 4.7%, 5.4% and 7.4% respectively after back-flushing the contaminated 14.2 ppg CaBr₂ brine formulated with 8% ZnBr₂. The net results obtained from these experiments are plotted in Figure 5. It is clear from this figure that, ZnBr₂ reduced the damage ratio for all used sandstone core samples and Khafji sandstone core sample has higher damage ratio than those for other sandstone core samples.

Effect of surfactant

The results obtain that, a very small quantity of surfactant (span 80) is required to reduce the surface tension of 14.2 ppg CaBr₂ brine from 82.7 to 33.5 dynes/cm and it is enough to reduce the interfacial tension between completion fluid and crude oil from 7.8 to 4.4 dynes/cm. To study the effect of high-density brine completion fluids formulated with surfactant on permeability restoration for various formation, same experimental have been carried out using core samples different in both amount and type of clay, and 14.2 ppg CaBr₂ brine without any additive and 14.2 ppg CaBr₂ brine formulated with 0.03% surfactant as completion fluids. Figures 6-9 show the results obtained in this regard.

Figure 6 shows that, the damage ratio of Berea sandstone core sample decreases with increasing oil pore volumes injected when about 5 pore volumes were injected, after that damage ratio was constant. Minimum damage ratio of Berea sandstone core sample is 22.6% after back-flushing the contaminated 14.2 ppg CaBr₂ brine without any agent, and it is 2.1% after back-flushing the contaminated 14.2 ppg CaBr₂ brine formulated with 0.03% surfactant. Figures 7-9 obtain that the minimum damage ratio of Aramco-1, Aramco-2 and Khafji sandstone samples after back-flushing the contaminated 14.2 ppg CaBr₂ brine without any agent are 18.9%, 27.1% and 33.8% respectively and they are 1.2%, 11.6% and 19.2% respectively after back-flushing the contaminated 14.2 ppg CaBr₂ brine formulated with 0.03% surfactant. The net results plotted in Figure 10. It is clear from this figure that, surfactant reduced the damage ratio for all used sandstone core samples and Khafji sandstone core sample has higher damage ratio than those for other sandstone core samples. The permeability restoration for all used sandstone core samples are estimated and plotted in Figures 1-10.

It is observed from this figure that permeability restoration by ZnBr₂ for Berea, Aramco-1, Aramco-2 and Khafji sandstone samples are 17.8%, 14.2%, 21.7% and 26.4% respectively. The permeability restoration by surfactant for Berea, Aramco-1, Aramco-2 and Khafji sandstone samples are 20.5%, 17.7%, 15.5% and 14.6% respectively. It's clarified that, for Berea and Aramco-1 sandstone core samples, the permeability restoration by surfactant is higher than that obtain by ZnBr₂. However, for Aramco-2 and Khafji sandstone core samples, the ZnBr₂ is more efficient than the surfactant. Formation damage by completion fluids caused by precipitate formation and by generation of fine due to interaction of invaded fluid and matrix. Various forces between particles, fluid and pore wells govern the retention and mobilization of fine particles within the porous media. The major forces including van dar Walls, electrical double layers, chemical bonding hydrodynamic drag, and friction force. The dominating forces depend on the size of particles [5].

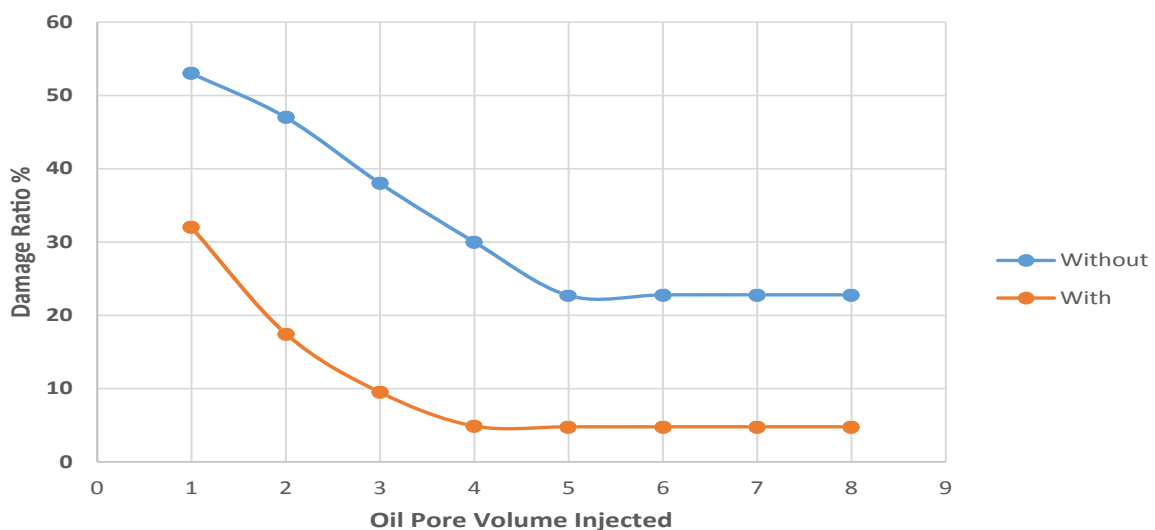


Figure 1: Effect of ZnBr₂ on damage ratio of Berea sandstone core sample.

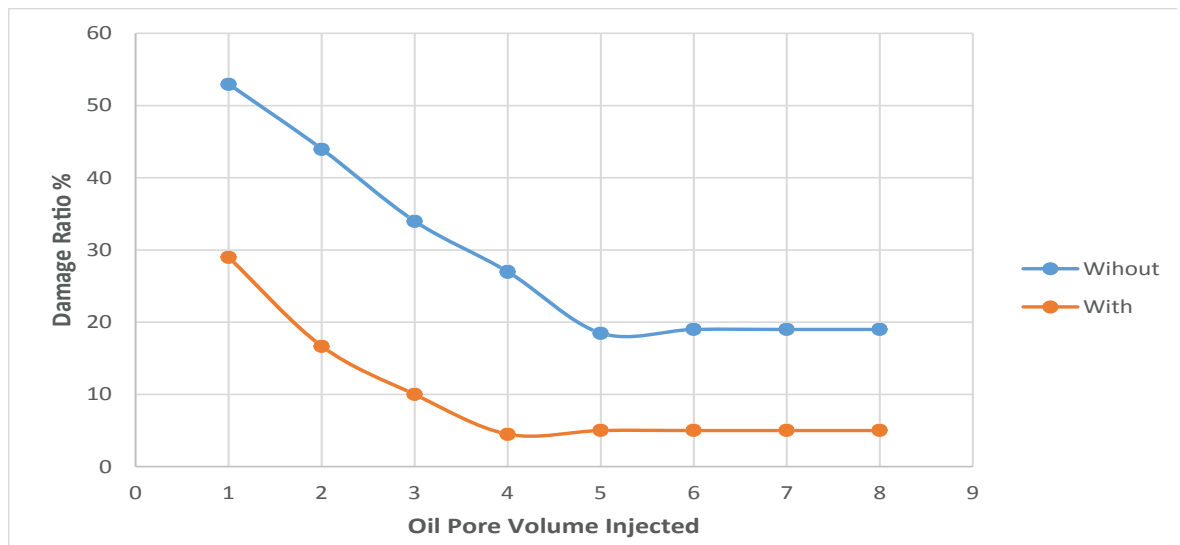


Figure 2: Effect of ZnBr₂ on damage ratio of Aramco-1 sandstone core sample.

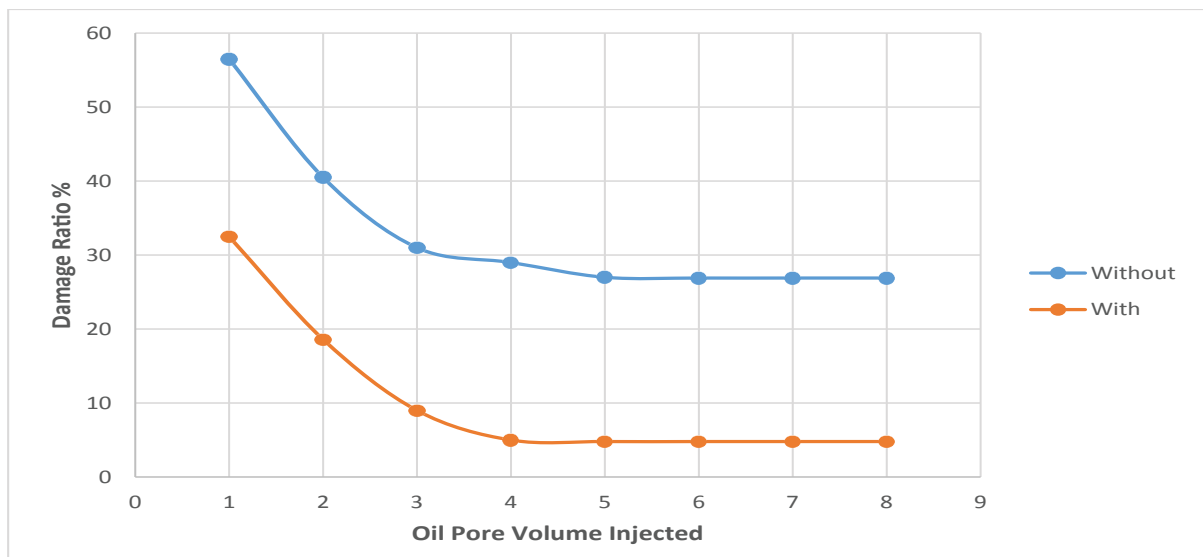


Figure 3: Effect of ZnBr₂ on damage ratio of Aramco-2 sandstone core sample.

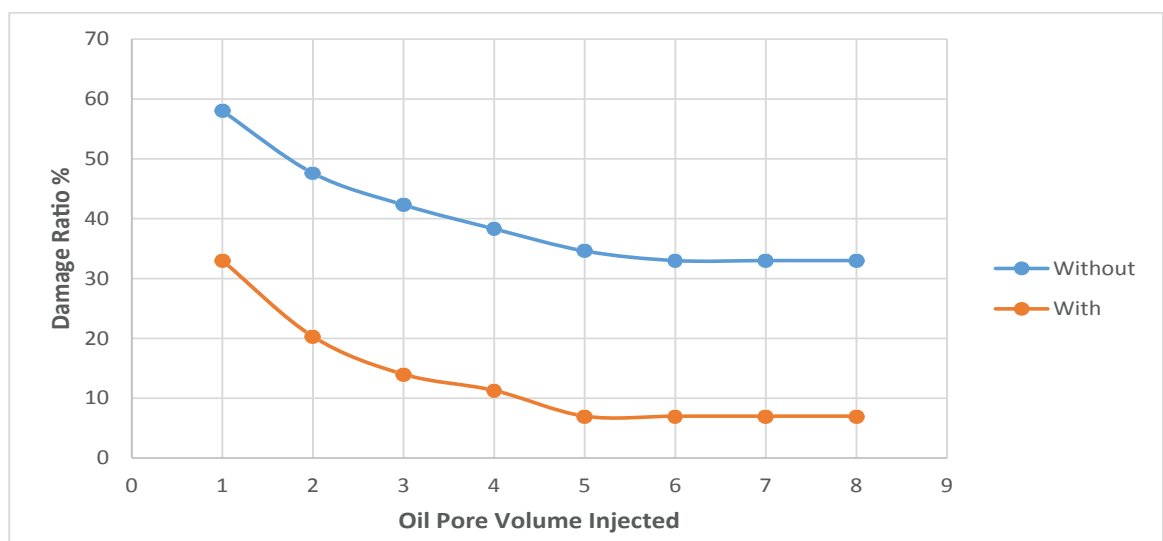


Figure 4: Effect of ZnBr₂ on damage ratio of Al-Khafji sandstone core sample.

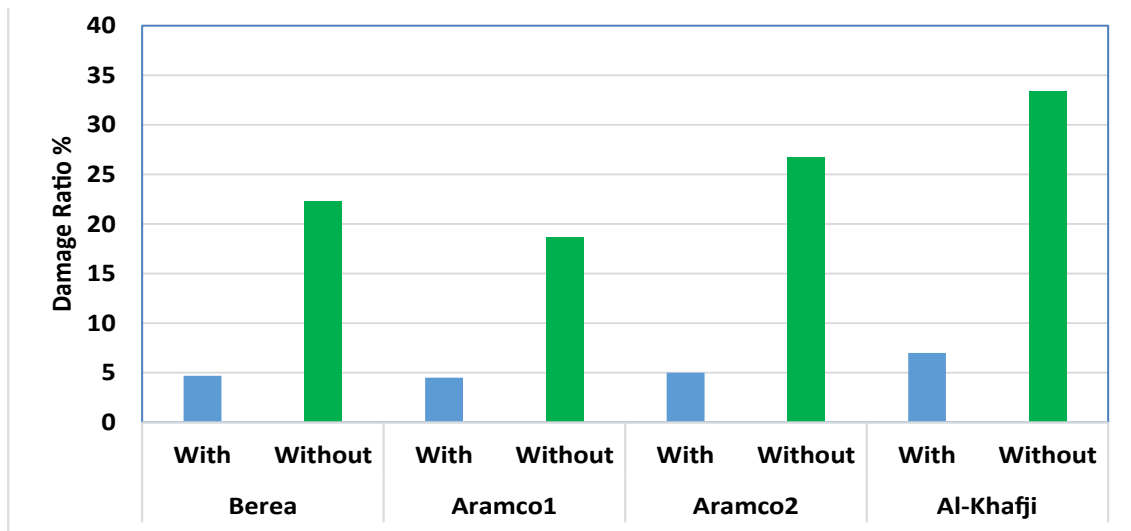


Figure 5: Effect of ZnBr₂ on damage ratio of different sandstone core samples.

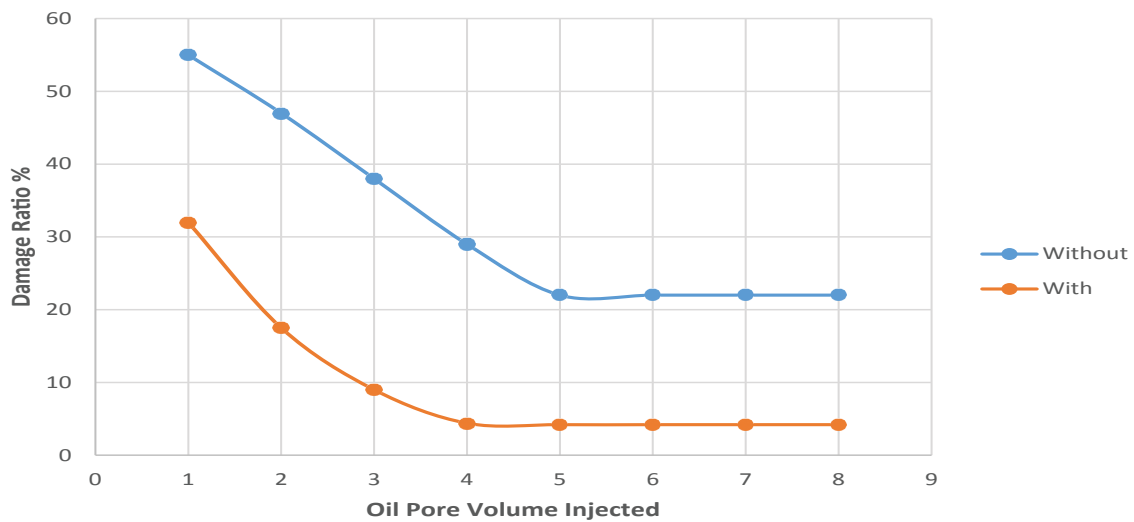


Figure 6: Effect of surfactant on damage ratio of Berea sandstone core sample.

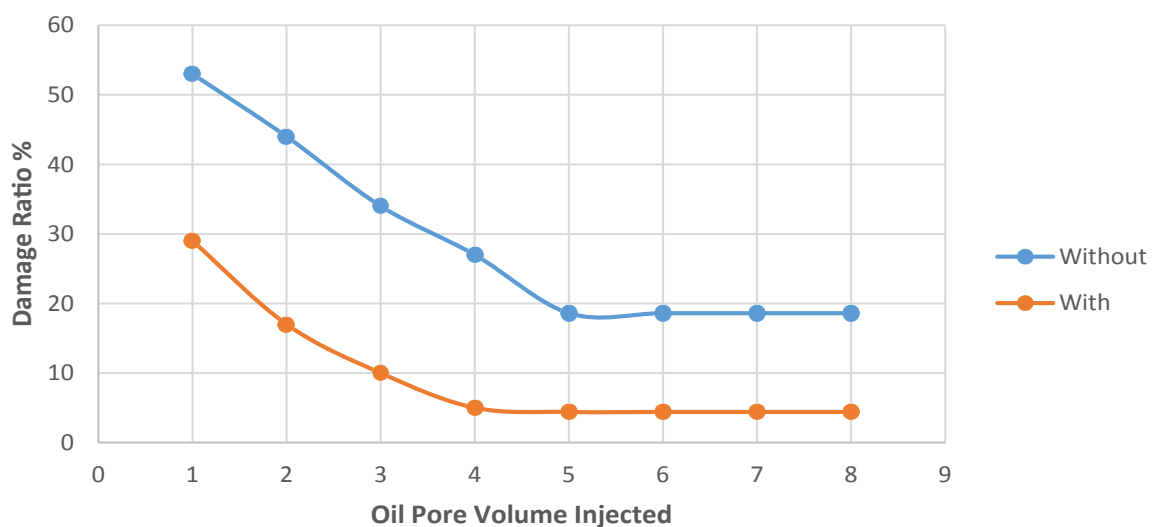


Figure 7: Effect of surfactant on damage ratio of Aramco-1 sandstone core sample.

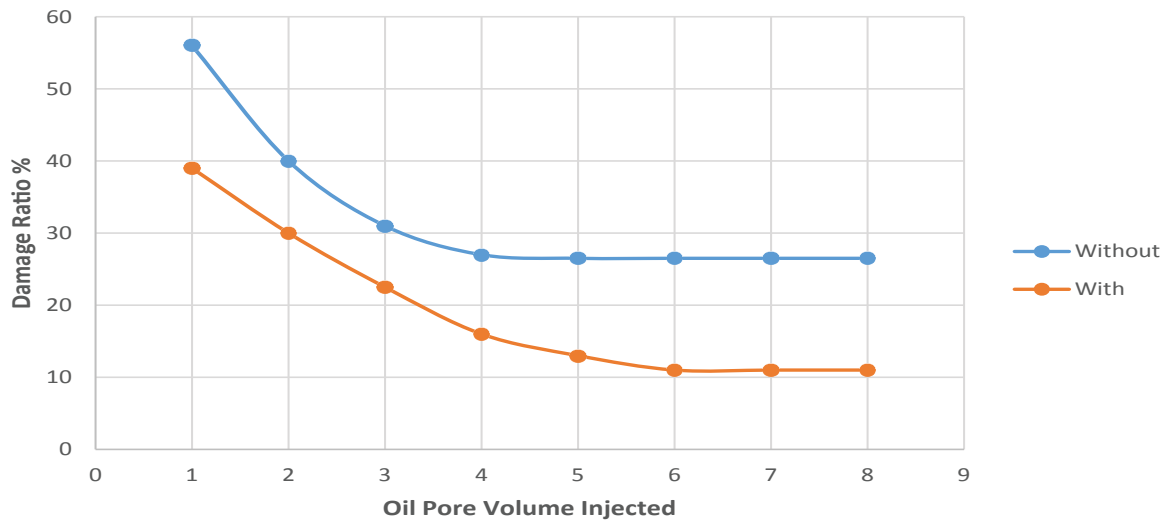


Figure 8 : Effect of surfactant on damage ratio of Aramco-2 sandstone core sample.

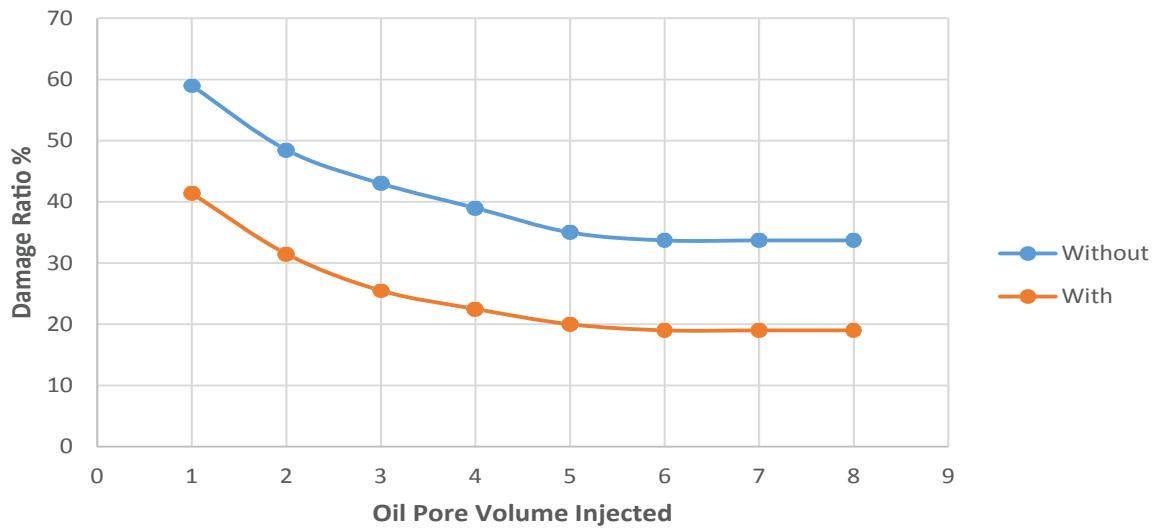


Figure 9: Effect of surfactant on damage ratio for Al-Khafji sandstone core sample.

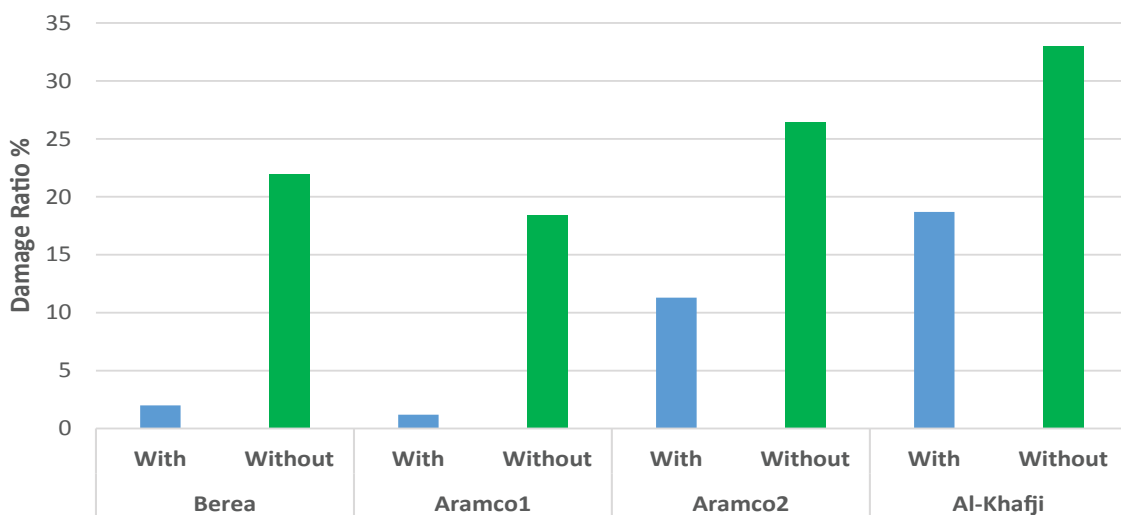


Figure 10: Effect of surfactant on damage ratio for different sandstone core samples.

Low pH considerably inhibits the precipitation and the degree of generation of fine from loose clays attached to the matrix. Lower surface tension reduces the production of fines by decreasing the drag force during dynamic flow conditions. For Khafji and Aramco-2 sandstone core samples, which have high percentage of particles that are classified as fines, the effect of lowering pH is more effective this is attributed to lowering pH effects on van der Waals and electrical forces, which are the dominating forces on the retention and mobilization of particles of a few microns in size [5]. For Berea and Aramco-1 sandstone core samples, which have low percentage of particles that are classified as fines, the effect of lowering surface tension is more effective this is attributed to lowering surface tension effects on friction and hydrodynamic drag forces, which are the dominating forces on the retention and mobilization of particles larger than 30 microns [5].

CONCLUSIONS

1. Permeability restoration of sandstone core strongly depends upon the amount of swelling clays.
2. The addition of surfactant or $ZnBr_2$ to high-density completion fluids increases the permeability restoration for all sandstone formation types.
3. Permeability restoration caused by addition $ZnBr_2$ is more than that by addition surfactant for dirty sandstone formation.
4. Permeability restoration caused by addition surfactant is more than that by addition $Zn Br_2$ for clean sandstone formation.

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