

Effect of Water Salinity on Shale Reservoir Productivity

Samiha Morsy^[a]; J. J. Sheng^{[a],*}

^[a] Petroleum Department, Texas Tech University, USA.
*Corresponding author.

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Abstract

It is well known that rocks containing water-reactive clays may swell when contacting with fresh water. In a conventional formation, this swelling may cause wellbore stability problem or damage formation by reducing its permeability. However, the effect of water salinity on shale rocks may be different. This issue is investigated in this paper. Shale rocks were immersed in water of different salinities. Shale rocks used were Mancos, Marcellus, Barnett and Eagle Ford. Different concentrations of NaCl and KCl salt solutions from 0% to 30% by weight were added in the water. It was observed that Mancos core plugs were crushed into loose grains (fragmented) at low salinity solutions up to 15%. Barnett core plugs showed consecutive cracks along bedding planes at low salinities. Minor cracks were seen on Marcellus, while no visual cracks were found in Eagle Ford core plugs at low salinities. When the shale plugs were saturated with oil, 2% - 15% oil was recovered by water spontaneous imbibition, depending on water salinity and rock mineralogy. Similar observations were made when shale core plugs were applied to an overburden pressure. The results from this paper help us to understand the drive mechanisms in shale oil and shale gas reservoirs. It also stimulates us to explore new ways to improve oil and gas recovery in shale reservoirs.

Key words: Water salinity; Shale reservoir; Oil and gas recovery

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INTRODUCTION

When fresh water contacts some clays like smectite (montmorillonite), these clays swell. Clays consist of negatively charged aluminosilicate layers kept together by cations. The characteristic property of clays to adsorb water between layers results in a strong repulsive forces and clay expansion^[1-10]. Clay swelling depends mainly on clay composition and can be caused by ion exchange and changes in salinity. The strong relation between clay composition and swelling can be explained by the concept of cation dissociation^[11]. Based on the cation dissociation concept, when a clay of the montmorillonite group is dispersed in water, the associated cations between the clay structure sheets tend to dissociate, prying the particles apart and leaving some of the structural units negatively charged. The negatively charged units tend to repel each other, and, if enough units are so charged, the repulsive forces are great enough to give the clay particles the appearance of swelling.

Clay minerals in their platy surfaces consist of either oxygen or ions organized into a hexagonal network, or of hydroxyl ions organized into a closely packed network^[12]. Clays swells differently depending on the amount and kind of exchangeable cations present on their surfaces, and in the seat of excess negative charge of the crystal lattice which these cations neutralize^[13]. One of the possible causes for the polarization of clay surfaces is the scarcity of the exchangeable cations relative to the number of surface oxygen ions, as for example, the ratio of oxygen ions to the cations may range from 18 to 1 in the montmorillonite group.

The swelling clays occupy some of pores thus reducing rock permeability^[14-20]. The reduction in rock permeability depends on the clay composition and the distribution, ionic composition and pH of the permeating fluids^[21]. Therefore, when waterflooding conventional sandstone reservoirs with high clay contents, inhibitors like KCl are added to the injected water to prevent clay swelling^[22].

However, in drilling wells through shale intervals, inhibitors are added in the drilling fluid (mainly water) to prevent clay swelling which causes mud loss^[23-26]. Mud loss indicates the shale permeability or flow capacity is significantly increased near the wellbore. These two practices indicate that the shale rock-water interaction in the two situations is different. Why is it different? Also, proppants are generally used to maintain the fractures open in conventional fracturing jobs^[27]. However, slick water (almost no proppants added) is successfully practiced in fracturing shale reservoirs^[28]. We also observed in laboratory that some shale rocks cracked when contacting with some water during our oil recovery experiments^[29]. Another research done on Bakken shale cores showed that there is an increase in shale permeability after spontaneous imbibition into brine due to cracking from clay swelling^[30]. Dehghanpour et al.^[31] measured spontaneous imbibition of aqueous (deionized water and KCl solutions of various concentrations) and oleic (kerosene and iso-octane) phases in several dry organic shale samples. They found that the imbibition rate of aqueous phases is much higher than that of oleic phases. They suggested that one of the causes to the excess water intake was the enhancement of sample permeability through adsorption. These observations indicate that fracturing fluids can keep fractures open.

Generally, shale reservoirs have laminated beddings in the form of heavily disk-like cores from vertical wells and small broken cores from deviated wells. In addition, shales show networks of smaller weak planes and natural fractures^[32]. The formation conditions near these fractures resemble those near a borehole. Therefore, we could expect the reactive fluids to improve the flow capacity near fractures. Actually, a few operators have suggested that water adsorbed by minerals in the rock creates localized clay swelling that may serve to hold open small fractures and fissures^[33]. This paper is to investigate the effect of water salinity on shale rock stability and fracturing in laboratory.

1. EXPERIMENTAL PROCEDURE

In this paper, water with different salinities was used to extract oil from different shale rocks by spontaneous

imbibition. In the spontaneous imbibition, the shale core plugs were initially saturated with oil and then put in Amott imbibition cells filled up with water of different salinities. The oil volume displaced by water was accumulated in the top of the Amott cells. The oil used was mineral oil (Soltrol 130TM). The salinities used were 0, 5, 10, and 15 wt% of NaCl and KCl. Core samples from Eagle Ford shale reservoirs and outcrop samples from Mancos, Barnett, and Marcellus shales were used. The core samples were 2.54 to 3.81 cm in diameter and 0.762 to 5.08 cm in length.

The porosities of samples are measured using weight difference and CT Scanning analysis methods. The Eagle Ford samples were dried after toluene extraction before the experiments as they contained reservoir oil.

All of the samples were saturated with the mineral oil for one week after they had been vacuumed for 24 hours. The porosities were measured again by the weight difference method as follows (Equation 1):

$$\phi = (W_{wet} - W_{dry}) / (\rho_{oil} V_b) \quad (1)$$

where ϕ is the porosity in fraction, W_{dry} is the dry weight of the sample before being saturated with the mineral oil, W_{wet} is the weight of the sample after saturation, ρ_{oil} is the oil density, and V_b is the shale sample bulk volume. Then the samples were placed in Amott cells with fresh water for one week and oil recoveries were recorded versus time.

With the CT images of the air-saturated samples and oil-saturated samples, the porosity was calculated the equation below (Equation 2):

$$\phi = \frac{CT_{cm} - CT_{am}}{CT_o - CT_a} \quad (2)$$

where CT is a CT number, and the subscripts o, a, om, and am donate oil, air, oil-saturated samples, and air-saturated sample, respectively.

2. SHALE ROCKS USED IN THIS PAPER

Reservoir core samples from Eagle Ford, and outcrop samples from Mancos, Barnett, and Marcellus shale formations were used in this paper. The formations have different mineral assemblages, ranging from the calcite-clay rich, quartz-poor Eagle Ford shale^[34-35], to the quartz-illite rich, carbonate poor Mancos^[36] (Table 1).

Table 1
Typical Mineral Abundances for Studied Shales

Mineral	Barnett ^[37] (wt%)	Marcellus ^[37] (wt%)	Mancos ^[38] (wt%)	Eagle Ford* (wt%)
Quartz	35 - 50	10 - 60	36 - 43.4	9
Clays, primarily illite	10 - 50	10 - 35	30.2 - 42.4	26
Calcite, dolomite, siderite	0 - 30	3 - 50	9.5 - 18	53
Feldspars	7	0 - 4	5.2 - 8.8	2
Pyrite	5	5 - 13	1 - 2.6	4
Phosphate, gypsum, Apatite	trace	Trace	trace	1
Mica	0	5 - 30	trace	Trace

Note. * Data provided by an oil company.

Barnett is a very brittle gas bearing siltstone^[34]. The Barnett shale consists of marine clays, primarily illite and chlorite, detrital silt-sized quartz, silicified and carbonate bioclasts and fossils, interstitial organic carbon, and phosphate. Most Barnett shales are siliceous mudstones rich in quartz and may be considered argillaceous siltstones. Some of the Barnett lithofacies are insensitive to acid, due to low volumes of carbonate, but moderately sensitive to freshwater. Other lithofacies have higher abundances of carbonate, and are therefore more reactive to matrix acidizing^[39].

The Marcellus formation is dominated by black shale with some interspersed limestone beds^[37]. Bedding is well developed and, as one would expect of shale, it often splits along bedding planes. Pyrite is also relatively rich in this shale.

The Mancos is predominately steel-gray sandy shale but includes stringers of earthy coal, impure limestones, and many thin beds of fine-grained yellow and brown sandstone that are chiefly composed of sub angular and angular quartz grains cemented by lime^[36].

The Eagle Ford shale contains a much higher volume and highly variable volumes of carbonate. At deeper

structural levels, which are exploited in South Texas, there is upwards of 70% carbonate. With progression towards the northwest, the clay content increases, as the formation is exploitable at shallower depths. The high percentage of carbonate makes it more brittle and “fracable”^[34-35].

3. RESULTS AND DISCUSSION

In this section, shale behaviors when exposed to water with different salt concentrations and the oil recovery for different shales are presented.

3.1 Shale Behavior When Contacting With Water

The visual observations of the samples exposed to fresh water during spontaneous imbibition showed that Mancos samples were most sensitive to fresh water as the samples were highly damaged due to severe hydration. The Barnett samples showed several cracks when exposed to fresh water (distilled water) with good core stability. There were cracks on the Marcellus shales, although they are not clearly seen in the Figure 1. Eagle Ford samples were least sensitive to water salinity with no cracks seen in Figure 1, probably because of less swelling clays in the samples, as shown in Table 1.



Figure 1
 Mancos Samples Looked Like in Water Less Than 15 wt% NaCl or KCl, Barnett, Marcellus, and Eagle Ford Shale Samples Looked Like in Fresh Water

3.2 Shale Oil Recoveries When Exposed to Fresh Water

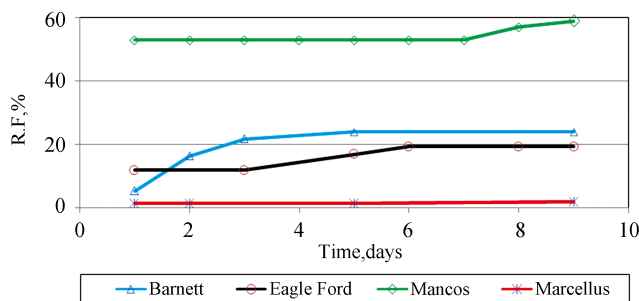


Figure 2
 Oil Recovery Factors (RF) in Spontaneous Imbibition in Fresh Water From the Barnett, Eagle Ford, Mancos, and Marcellus Shale Samples

The oil recoveries from the Mancos, Barnett, Marcellus, and Eagle Ford samples exposed to fresh water are

presented in Figure 2. The recovery factor of Mancos was the highest (59%) among all of the samples because the samples were fragmented and it was easier for oil to come out the shale sample. Eagle Ford and Barnett recovered 20% and 24%, respectively. The cracks were induced over time in Barnett samples when exposed to the distilled water. As a result, more oil was recovered. Although no fractures were visually seen in the Eagle Ford sample, the high oil recovery factor was obtained. It is believed that the Eagle Ford sample had better-connected pores. Marcellus sample showed the lowest recovery of about 2% somehow.

3.3 Mancos Shale Behavior When Exposing to Water of Different Salinities

The Mancos samples when exposed to a lower salinity (< 15% of NaCl or KCl) showed significant damage after

one week of spontaneous imbibition as shown in Figures 3 and 4. Figure 3 shows that the Mancos shale samples had cracks and became fragmented to different degrees depending on the salinity. At 5% and 10% NaCl, the rock samples were fragmented. When the concentration was at 15%, the sample had fewer cracks. When the Mancos samples exposed to water of 30% of KCl, they showed very few cracks, as shown in Figure 4. Reviewing the Mancos formation, we found that Mancos formation water is very saline with 13.8% - 21.2%^[40]. It means that the formation rock is stable in the formation water salinity range. The oil recoveries from Mancos samples in different saline water solutions are shown in Figure 5. The oil recovery factor was enhanced up to 59% from the samples exposed to the 5% NaCl solution compared with only 4% from the samples exposed to the 30% NaCl solution. More oil was recovered from the Mancos sample exposed to the 5% NaCl solution than that from the sample exposed to the 10% or 15% NaCl solutions, because the sample in a lower salinity solution was more fragmented. The shale samples in the KCl solutions were more stable compared with the NaCl solutions, as shown in Figures 3 and 4.



Figure 3
Mancos Samples in 5%, 10% and 15% NaCl Solutions



Figure 4
Mancos Samples in 5%, 15% and 30% KCl Solutions

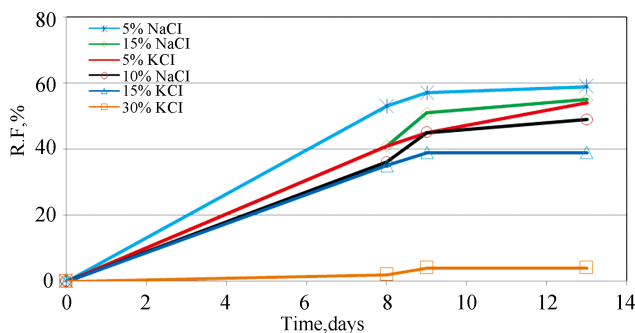


Figure 5
Oil Recovery Factors of the Mancos Shale Samples After Spontaneous Imbibition in Different Saline Solutions

3.4 Eagle Ford Shale Behavior When Exposing to Water of Different Salinities

Distilled water gave higher recovery factor compared with 2% KCl due to clay swelling that could result in microfractures opening. The distilled water recovery factor was about 19.4% compared with 12% from the 2% KCl brine solution (Figure 6).

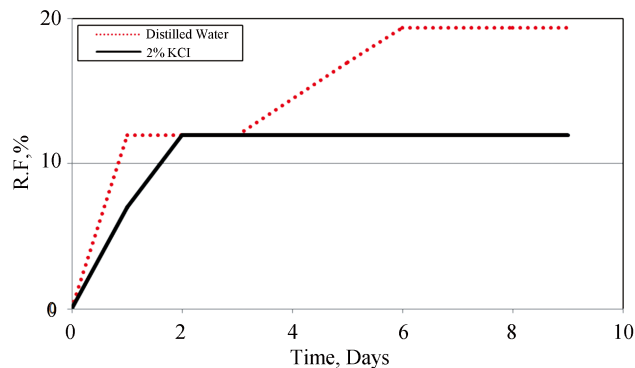


Figure 6
Spontaneous Imbibition Experiment Oil Recovery Factors for the Eagle Ford Shale Samples

3.5 Mancos Shale Stability Test Under Confined Condition

The shale behaviors presented in the preceding sections were under unconfined stress conditions. A further test under a stressed condition using Mancos shale was conducted. The experimental setup was as following. The shale core plug was put in a core holder. The radial confining pressure was set at about 700 psig. The inlet injection pressure was set at 150 psig and the outlet pressure was set at 42 psig. Fresh water was constantly injected at the set injection pressure. The lab set up had a data acquisition system so that the pressures can be recorded and monitored. After 73 hours, the core plug was taken out of the core holder. Figure 7 shows that the picture of the core plug. The core plug was not fragmented, but some fractures were generated and could be seen on the core surfaces. Water came out along the fractures as shown in dark lines. Figure 8 shows that one corner was broken because of fractures. After the plug was withdrawn for some time, the dark lines were

invisible because water vaporized. But minor fractures remained, as shown in Figure 9. These pictures show that the fractures could be created by clay swelling under confined stress conditions.



Figure 7
Dark Water Lines Showed Generated Fractures After the Core Plug Was Taken out of the Core Holder



Figure 8
The Corner Was Broken Because of Generated Fractures



Figure 9
Fractures Remained After the Water Vaporized

CONCLUDING REMARKS

The experiments presented in this paper clearly show that the shale rocks were very sensitive to water salinity. With lower salinity, shale samples were more fragmented or fractured. The sensitivity was also in line with the swelling clay contents in the shales, although we did not measure the exact contents of the minerals, which will be our future work. The oil recovered from water imbibition was in line with the degree of shale fragmentation and fracturing. Therefore, understanding the interaction between shale rock and water salinity is very important in shale oil and gas recovery.

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