

EXPERIMENTAL INVESTIGATION OF SCALE FORMATION AND PREDICTION BY A NOVEL METHOD, ELECTRICAL CONDUCTIVITY

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ABSTRACT

One of the most serious problems in the water injection process is scale formation occurrence when injection water is incompatible with formation brine. These two waters interact chemically and precipitate inorganic minerals. For example seawater with high concentration of sulfate ions as injection water reaches to formation water with cationic ions. The purpose of this study is to predict the permeability reduction caused by deposition of scales in sandstone cores from mixing of injected sea water and high salinity formation water at various temperatures (60-100 °C) and differential pressures (50-150 psig). A very common way to predict the scale formation is running core flood experiments in a way that first, the core was saturated with formation brine and set to desired temperature then sea water was injected at a constant pressure and continuously by measuring flow rate the permeability was recorded with time. But several factors like particle movement, clay swelling and pore throat blocking by fines migration can disturb flooding test results and make doubt in predictions. As a new method by measuring the electrical conductivity of outlet water the scale formation was predicted independent of non-related parameters mentioned above. Electrical conductivity of outlet water dropped out of the range between injection and formation water electrical conductivities, so it shows a decrease in free ion concentration in mixed waters as a result of scale formation and precipitation in core. The results showed that calcium, strontium, and barium sulfates are formed and cause permeability damage. CaSO₄ and SrSO₄ scales will deposit more in higher temperatures but BaSO₄ scale deposit less. At higher pressures all of them precipitate more.

Keywords: Formation damage, Incompatible waters, Inorganic scale formation, core flood, permeability decline, Electrical Conductivity.

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1. INTRODUCTION

Water injection as a secondary recovery mechanism is one of the best methods for pressure maintenance during production that causes an increase in recovery, especially in offshore and near coastal oil fields by considering the availability of seawater. But since formation waters usually are hyper saline waters with alkaline cations such as calcium, strontium and barium and at the other hand seawater contains a considerable concentration of sulfate ions so an injection of seawater without proper removal of sulfate could cause sulfate scale deposition in any point that water mix [1]. Deposition of sulfate scales will cause operational problems and difficulties, which finally increase operating cost. For example, sulfate scale deposits are hard, insoluble in mineral acids or other common solvents, and very difficult to remove mechanically. These deposits could restrict flow both in the near wellbore region and in equipment [2]. Knowledge of type and amount of probable precipitations is very important to prevent Damages. One of frequently used methods is running core flood experiments in which two waters mix in core and result in permeability reduction [3]. This reduction is calculated by pressure or flow rate recording that are under the effect of other non-related phenomena like pore throat plugging by sand movement or clay swelling. By measuring the electrical conductivity of output water the reduction in concentration of free ions can be measured that is a sign of scale formation regardless of other factors.

1.1 Scale formation

Inorganic scaling is the deposition of scales from aqueous solutions when they become supersaturated after a change in their thermodynamic and chemical equilibrium states. Inorganic scaling can occur in many places like well tubing and near well bore formations of the production and injection wells [4].

Inorganic scale forms primarily when supersaturated condition is prepared. This condition occurs when a solution contains dissolved materials at higher concentrations than their equilibrium concentration. Higher supersaturation condition implies higher possibilities for scale deposition because the driving force for the precipitation reaction is the degree of supersaturation that is known as scaling index or SI [5].

1.2 Types of scale

In oilfield operations because of sea water usage the most common scales are sulfates such as calcium sulfate (anhydrite, gypsum), barium sulfate (barite), and Strontium sulfate (Celestite) and calcium carbonate [6].

2. Experimental procedure and materials

Laboratory tests were designed to study permeability reduction by deposition of calcium, strontium, and barium sulfates in a porous medium and how their alterations are affected by changes in differential pressure and temperature.

2.1 Core Material

The rock cores used in the testes were sandstone with 10 cm length and of diameter 37mm with average porosity of 27 % and of absolute permeability varied from 2.14 to 3.05

md. No oil was present in the cores. All the cores were cleaned using methanol in Soxhlet extractor and dried in Oven at 110 °C for overnight before use.

2.2 Brines

There are three types of formation water that are brines with calcium, strontium, and barium ions. The Ionic compositions of synthetic formation waters and injection water (Persian Gulf seawater) are given in Table 1. Note the sea water contains sulfate ions. It is clear that the mixing of these waters can lead to calcium, strontium and barium sulfate precipitation.

Table 1. Ionic composition of formation and injection brines (concentration in mg/l).

Ion	Persian Gulf SW	High calcium FW	High barium FW	High strontium FW
Calcium	520	10000	-	-
Barium	-	-	2000	-
Strontium	-	-	-	1500
Sulfate	3100	550	550	550
Bicarbonat	171	488	500	500
Sodium	13044	75198	75000	75000
Chloride	23000	136675	136700	136700
Total	41395	224411	216250	215750

2.3 Apparatus

To prepare suitable cores for experiments some apparatus like core cutter, soxhlet extractor, oven and vacuum pump are used which have less importance so there is no need to describe them.

Test rig: Experiments were carried out using a test rig, which is schematically shown in Figure 1. The core test equipment consists of four parts: constant pressure/constant flow rate pump, transfer cell, oven and core holder. There follows a brief description of each part.

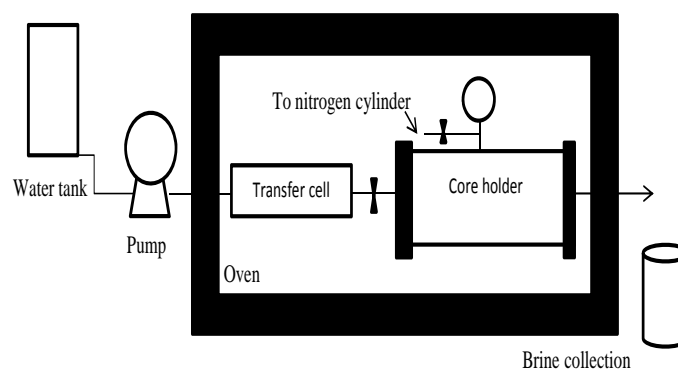


Figure 1. Schematic of the core flooding apparatus.

Constant pressure/flow rate pump: Syringe pump manufactured by isco industry model 260D, with maximum design pressure of 7500 psi and flow rate between 0.001-107 ml/min was used to inject the brines during flooding at different pressures.

Transfer cell: Stainless steel transfer cell which can withstand pressures up to 5700 psia at 200°C was used to store and pump the injected brine to the core holder. The cell with a capacity of 1000 ml has a free-floating piston, which separates the pump fluid (distilled water) from the injection brine. The pump fluid was pumped into a transfer cell to displace the brine into the core.

Oven: During all flooding runs, the core holder and transfer cell are placed inside a temperature controlled oven.

Core holder: A stainless steel core holder designed for consolidated core samples, 20 cm length and 6 cm diameter, was used. The holder could withstand pressures up to 5500 psia at 200°C. A rubber sleeved core holder, subjected to an external confining pressure, into which a sandstone core is placed.

Electrical conductivity meter: Electrical conductometer model Sartorius that measures the electrical conductivity in a solution. Commonly used in hydroponics, aquaculture and freshwater systems monitor the amount of nutrients, salts or impurities in the water.

2.4 Test procedures

For each run, the core sample was cleaned with methanol in a soxhlet then was dried in Oven at 110 °C for overnight. The core sample was prepared for installation in the core-holder. A vacuum was drawn in the core sample for several hours to remove all air from the core. The core was saturated with formation water at room temperature, and a base permeability determined. After the appearance of formation water at the outlet flooding was continued long enough to ensure complete saturation. The core holder assembly placed inside the oven and transfer cell containing sea water was also placed inside the oven and heated to the desired temperature of the run. The required confining pressure was then adjusted to be approximately at 500 psi more than the inlet pressure. A flooding run was started by setting plunger pump at different pressures. Thus, the sea water was injected into the core and mixed with formation water inside porous media. The inlet pressure was monitored on the pump screen while the outlet pressure was atmospheric pressure. During each run, the flow rate across the core was recorded continuously and the permeability of the core was calculated with Darcy's linear flow equation before and after scale deposition.

To show scale formation occurrence by electrical conductivity measurement, each 2 ml of outlet water was collected in a beaker and diluted with 6 ml of fresh water to avoid precipitation.

After measuring water conductivities, the decrease in ion concentration was observed.

3. RESULTS AND DISCUSSION

This part of the investigation is about the study of permeability reduction caused by scale deposition in porous media. The core flood experiments were designed to investigate the role of temperature (60-100 °C) and differential pressure (50-150 psig) of calcium, strontium, and barium ions.

During each run, the flow rate across the core was measured by dividing the volume of water that exited from the pump tank by time period in minutes, and the permeability of the

core was calculated using Darcy's linear flow equation. The flow rate decreased during the experiments when a super-saturated solution was flowing through the cores. This confirms that the decrease in flow rate is due to precipitation of the calcium, strontium, and barium sulfates inside the core with the consequent reduction in its original permeability and porosity. In the following, extend of permeability damage, the decline trends of permeability ratio and the results for various temperatures and differential pressure are discussed.

Although, during core flood experiments, some factors may be effective in a decrease or increase in flow rate like presence of free sands in core, clay swelling or even behavior of fluid flow before establishing the steady-state flow. To remove these factors and predicts the scale formation phenomena in cores during seawater injection, electrical conductivity method was used.

During each run, in every 10 minutes of experiment, 2 ml of output brine was collected and immediately diluted with 6 ml of fresh water to avoid precipitation. Then by using a digital conductometer electrical conductivity of the samples was measured.

Electrical conductivity lower than both injection and formation water shows the decrease in ion concentration because of scale formation.

3.1 Effect of temperature

Temperature has a considerable effect on the solubility and crystal growth of sulfate scales. To survey its effect on the permeability reduction, a number of tests were carried out where the concentration of injected brine was kept constant at a differential pressure 100 psi and temperatures of 60, 80 and 100°C. Figure 8 shows the variation of permeability reduction with time at different temperatures when only barium is in formation water. The permeability decline is less rapid at a higher temperature, since the rate of BaSO_4 precipitation decrease with increase in temperature. This is because the solubility of BaSO_4 increases with temperature.

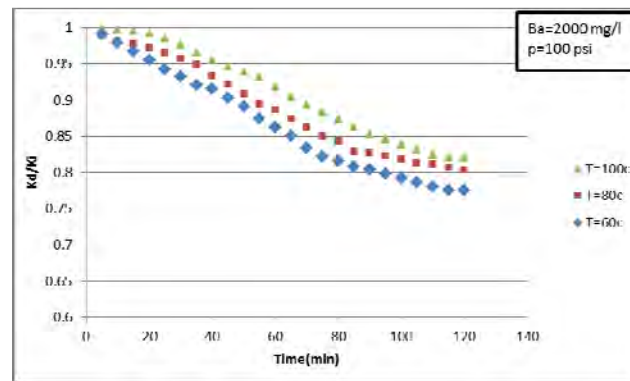


Figure 8. Damage ratio versus time showing the effect of temperature on BaSO_4 formation

Figures 9 and 10 show this effect for Calcium and strontium in formation water. It shows that at higher temperatures for calcium and strontium, the permeability declines more rapidly. This is because the rate of CaSO_4 and SrSO_4 precipitation increases with temperature. The increase in temperature also causes a rise in super-saturation, because the solubility of CaSO_4 and SrSO_4 decrease with temperature. This must have led to an increase in rate of precipitation and consequently, a faster permeability decline.

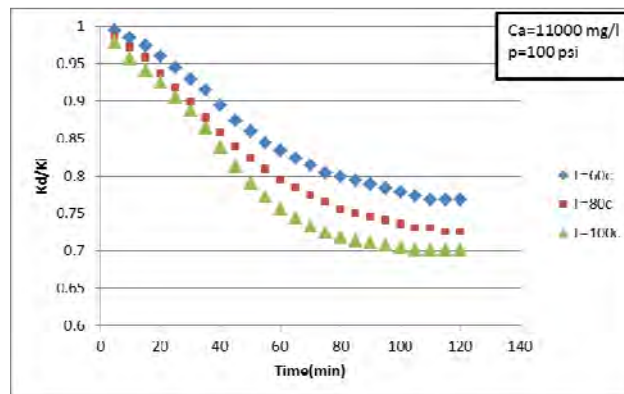


Figure 9. Damage ratio versus time showing the effect of temperature on CaSO_4 formation

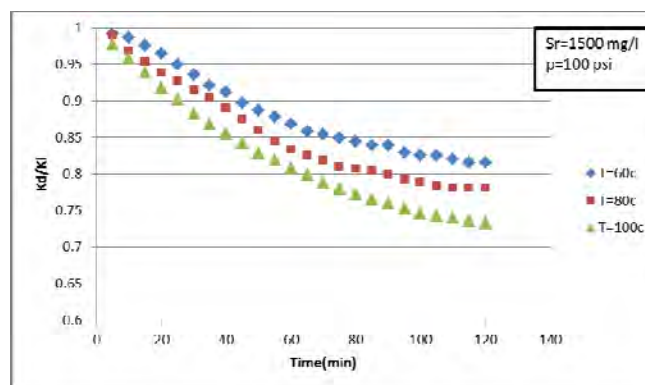


Figure 10. Damage ratio versus time showing the effect of temperature on SrSO_4 formation.

3.2 Effect of differential pressure

To study the effect of differential pressure on permeability reduction a number of tests were carried out. In these tests, the concentration of brine and temperature were kept constant and differential pressure varied from 50 to 150 psig. The extent of permeability reduction with time at various differential pressures is shown in Figures 11, 12 and 13. The results show even at low differential pressure, scale formation has a vital effect on the permeability decline. When the differential pressure was increased, the rate of permeability decline was increased. Moreover, at a higher differential pressure more sulfate ions will pass through the porous medium in a given interval. Therefore, the super-saturation at the porous medium will increase the rate of precipitation. This increased precipitation rate will cause a larger permeability damage.

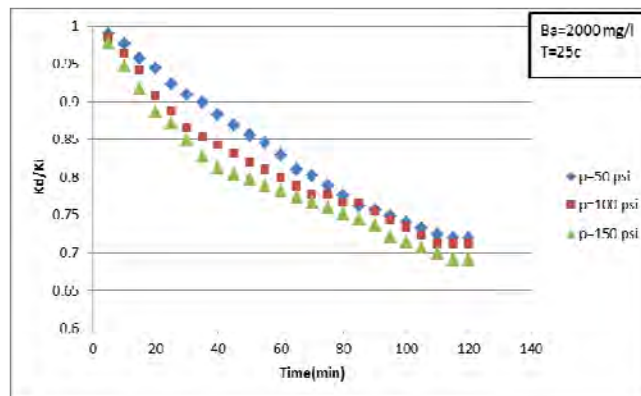


Figure 11. Damage ratio versus time showing the effect of pressure on BaSO₄ formation

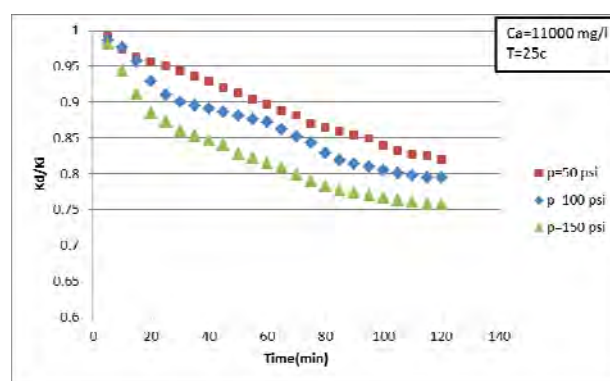


Figure 12. Damage ratio versus time showing the effect of pressure on CaSO₄ formation.

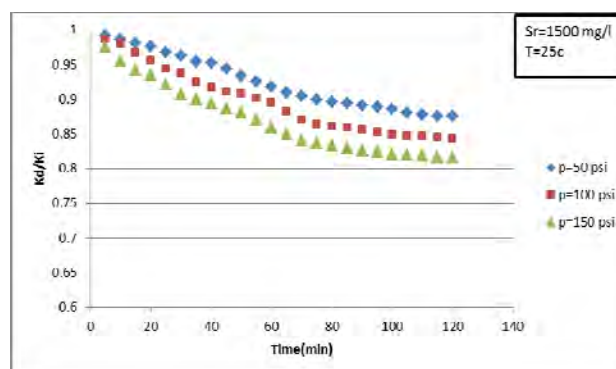


Figure 13. Damage ratio versus time showing the effect of pressure on SrSO₄ formation.

3.3 Electrical conductivity method

Figure 14 shows electrical conductivity of output water versus time for the run that Ca was in formation water at normal concentration.

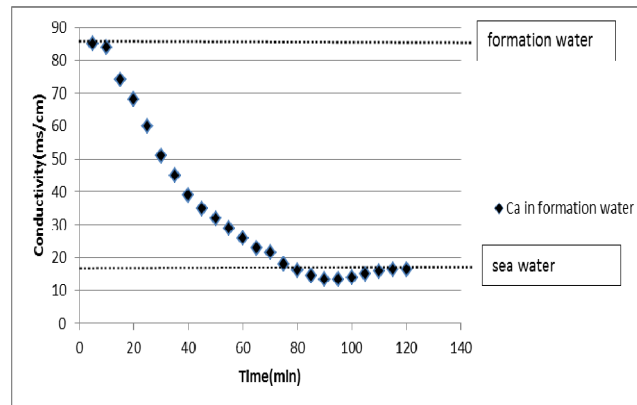


Figure 14. Variation of outlet water conductivity versus time.

Without scaling the conductivity of output water should be between seawater and formation water because it's a mixture of them. At times where conductivity is less than both waters scale is forming and some of the free ions that conduct electricity precipitate.

4. CONCLUSIONS

- 1) Damage in permeability caused by CaSO_4 , SrSO_4 , and BaSO_4 scale formation in the sandstone cores ranged from 13% to 30% of the initial permeability, depending on brine composition, temperature and differential pressure.
- 2) The worst damage occurred in the porous media is 30% of the initial permeability at a temperature (100 °C) and differential pressure (100 psig) for CaSO_4 experiment and the less damaged case is about 13% of the initial permeability at a temperature (25°C) and differential pressure (50 psig) for SrSO_4 test.
- 3) CaSO_4 and SrSO_4 scales form more in higher temperatures because their solubility's decrease by increase in temperature while BaSO_4 formation decrease in higher temperature because its solubility increase.
- 4) Differential pressure has a direct impact on supersaturation so in higher pressure permeability damage is more severe.
- 5) Effect of temperature on scale formation is dominant in comparison with differential pressure.
- 6) Analysis of output brine electrical conductivity can help to predict scale formation where pressure and flow rate of experiments are influenced by other possible occurrences.

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