Evaluation of thermodynamics effect on mineral scale formation in water injection wells supported by laboratory experiments

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ABSTRACT: Usually, some amount of unwanted water is being produced along with oil production in most of the oil fields. These waters are dangerous to environment and must be managed safely. In most cases, they are injected into water disposal wells. Scale formation and well plugging during water injection to disposal wells is a critical problem in waste water management. Main reasons for inorganic scale formation in these wells are incompatibilities of injection water and reservoir water, and thermodynamics condition variation of injection water. These mechanisms lead to the mineral scales precipitation and consequently, they are deposited in porous media which leads to injection rate reduction in water disposal wells. The critical place of scale formation is the well bottom. It is the entrance of injected fluids and commonly results in the increase of injection pressure and reduction of water injection. In the current study, the effect of pressure and temperature would be assessed on precipitation of inorganic scale by lab testing and software simulation at different mixing ratio of injection water to formation water. Also, some core flooding tests are run to evaluate the effect of deposited mineral scales on water injection process in the core samples. All input data of software modeling and core samples belong to a water injection well in a sand stone reservoir in south west of Iran.

1- Introduction

Inorganic scale formation is a challenging issue in the oil exploitation industry; usually, it causes reduction of water injection rate in water disposal wells and leads to high economic defeats and instrumental damages in this industry. On the other hand, this phenomenon can reduce the daily rate of oil production by blocking fluid transferring facilities [1-3].

Inorganic scaling can occur anywhere in production or injection system, at which the potential of supersaturation exists. Supersaturation leads to mineral scale precipitation and it happens due to variation of thermodynamics conditions or by mixing of different incompatible waters. Mineral scale formation is the most common water-related issue in the petroleum industry and can result in severe oilfield issues [4, 5].

The most common mineral scales in petroleum industries are 1: Carbonate based scales which occur due to changes in pressure and temperature that leads to release of CO_2 from flowing fluid. Famous scales of this group are $CaCO_3$ and $FeCO_3$. 2: Sulphate based scales that occur due to mixing of incompatible waters. Famous scales of this group are $BaSO_4$, $CaSO_4$ and $SrSO_4$. Carbonate scales formation takes place mainly through the well column of water injection wells, due to changes in thermodynamics conditions of injected fluid, while the sulphate scales formation takes place mainly near wellbore area where the injected water encounters the reservoir water [6-8].

Kan et al. [9] tried to identify experimentally the mineral scales composition at different mixing ratios of incompatible waters. A brine sample and real reservoir water were mixed at different ratios by jar testing. After ensuring the scale formation, scanning electron microscopy (SEM) and X-ray diffraction confirmed formation of $CaSO_4$, $SrSO_4$, and $CaCO_3$ at various mixing conditions. Final report of this study recommended the most suitable mixing ratio as 75% of brine to 25% of reservoir formation water [9-11].

Lu et al. [12] mentioned that the traditional techniques of scale formation only focus on the thermodynamic features of the initial and final condition of the mixing water system at different mixing ratios and very few studies have been done to evaluate the intermediate situations. A carbonate reservoir in Saudi Arabia that suffered from calcium sulfate scale was chosen to demonstrate a new scaling approach. Main reason for $CaSO_4$ formation in sand face of water injection wells of this oilfield was the high calcium content of reservoir formation water and high sulfate content of injected sea waters. They tried to predict the mineral scales formation and its impact on the reservoir parameters by coupling the chemical reactions and multiphase fluid flow in reservoir porous media. A 2-D model was built to simulate the effect of scale deposition on the reservoir performance in an oilfield during water flooding process at a 20 years operational period. The final simulation results showed that permeability distribution through the reservoir rock is the dominant parameter on the

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movement of precipitated scales and their deposition in porous media [12, 13].

Two stages of mineral scale formation are scale precipitation and scale deposition, consequently. Two main mechanisms which lead to inorganic scale precipitation are incompatibility between the injected and formation waters and changes in thermodynamics condition of injected water. And injectivity of disposal wells declines due to deposition of the precipitated scales at near wellbore region.

The effect of thermodynamics conditions on scale formation is an important issue during precipitation of scales. In this study, the effects of pressure and temperature changes have been evaluated separately by lab testing and software simulation on scale precipitation at different ratios of injected water and formation water. Also, the effect of deposited scales phenomenon is observed on water injection process by core flooding test.

2- Material and Methods
2- 1- Preparation of fluid samples
The main required fluid samples of this study are injection water and reservoir formation water. The injecting water was available from the injection line at the surficial entrance of disposal well. But the reservoir water should be made in laboratory the same as ion composition of the studied field produced water.

2- 2- Water analysis
The ionic composition of mentioned water samples would be analyzed in laboratory (as shown in Table 1); and will be inserted in OLIScaleChem software to make static model of scale precipitation.

2- 3- Temperature effect analysis
Scale formation will be modeled by OLIScaleChem software to evaluate the amount of precipitated scales at different temperatures (from surface to bottom hole temperature) while the pressure is set at constant amount of 13.8×10^6 Pa (2000 psia) which is the average fluid pressure through the well column.

2- 4- Pressure effect analysis
Scale formation will be modeled by OLIScaleChem software to evaluate the amount of precipitated scales at different temperatures (from ambient to reservoir pressure) while the temperature is set at constant amount of 65.5 °C (150 °F) which is the average fluid temperature through the well column.

2- 5- Evaluation of saturation indices
These parameters are computed to ensure scale precipitation:

- **Scale Tendency Index:** Scale Tendency Index can be used to check the validity of scale formation. Scale Tendency (ST) is defined as:

$$ST = \frac{Q}{K_{sp}} \tag{1}$$

where Q is activity coefficient and K_{sp} is solubility coefficient. If ST is more than 1 the solution is under saturated and the scale is possible to be formed, but if it is less than 1, the solution is over saturated and scale formation is impossible [14].

- **Scaling Index**: Scaling Index is known as saturation index and it is defined as:

$$SI = \log_{10}^{(ST)} \tag{2}$$

So when SI is positive the fluid is over saturated and mineral scale formation will be happened and when it is negative the fluid is under saturated and no scale will be observed [14].

Scale tendency and scale index were calculated to ensure the above results.

2- 6- Laboratory testing
Three nodes are randomly chosen for laboratory experiments to check the validity and accuracy of software modeling results of stages 2.3 and 2.4.

Table 1- Composition of reservoir water and disposal water

	HCO$_3^-$	SO$_4^{2-}$	Cl$^-$	Fe^{3+}	Mg^{2+}	Ca^{2+}	Na$^+$	K$^+$	Total
Reservoir water ionic specifications (ppm)	160	789	110502	187	1290	5230	65627	1392	**185177**
Disposal water ionic specifications (ppm)	73	376	125621	31	2410	13989	61029	1297	**204826**

Table 2- Thermodynamics specifications of temperature-sensitive analysis

Case no.	Temperature in ºC (Equivalent amount in ºF)	Pressure in Pa (Equivalent amount in psia)
1	37.7 ºC (100 ºF) {wellhead temp.}	$13.8×10^6$ Pa (2000 psia)
2	54.4 ºC (130 ºF)	$13.8×10^6$ Pa (2000 psia)
3	71.1 ºC (160 ºF)	$13.8×10^6$ Pa (2000 psia)
4	87.7 ºC (190 ºF)	$13.8×10^6$ Pa (2000 psia)
5	104.4 ºC (220 ºF) {reservoir temp.}	$13.8×10^6$ Pa (2000 psia)

Table 3- Cases of mixing ratios: injected water and reservoir water volume percentage

Case no.	Injected water ratio	Reservoir water ratio
1	0	100%
2	10%	90%
3	25%	75%
4	40%	60%
5	50%	50%
6	60%	40%
7	75%	25%
8	90%	10%
9	100%	0

2- 7- SEM (EDX) tests

The precipitated scales in stage 2.6 should be analyzed by SEM (EDX) tests to detect the type and amount of scales.

2- 8- Models' validity

Result of the software simulation and laboratory experiments should be compared to ensure the model's validity.

2- 9- Core flooding test

This test is carried out to evaluate the effect of scale formation on permeability of the reservoir rock sample. Core flooding tests should be done by injecting disposal water samples to the core saturated by synthetic formation water.

3- Results and Discussion
3- 1- Simulation of scale precipitation

After sampling of injection water and reservoir one, their ionic composition will be detected in laboratory. This is one of the most important input data to OLIScaleChem software.

3- 1- 1- Temperature effect on scale formation

The effect of main thermodynamics parameters (i.e. temperature and pressure) will be assessed on the scale formation in the studied water injection well in south west of Iran. For this purpose, the first sensitive analysis is carried out to evaluate the temperature effect at constant pressure. Table 2 shows the selected thermodynamics situations to simulate scale formation. Starting value of temperature is considered as average environment temperature and increased step wisely to the bottom hole which is facing the reservoir temperature. The selected pressure is the corresponding value at the middle of the well column, which was calculated at about $13.8×10^6$ Pa (2000 psia).

As mentioned in previous section (introduction), another critical parameter in scale formation issue is incompatibility between waters. So 5 different mixing ratios of injected water and reservoir water will be considered to improve the accuracy of simulation results. Table 3 represents different ratios of mixed waters.
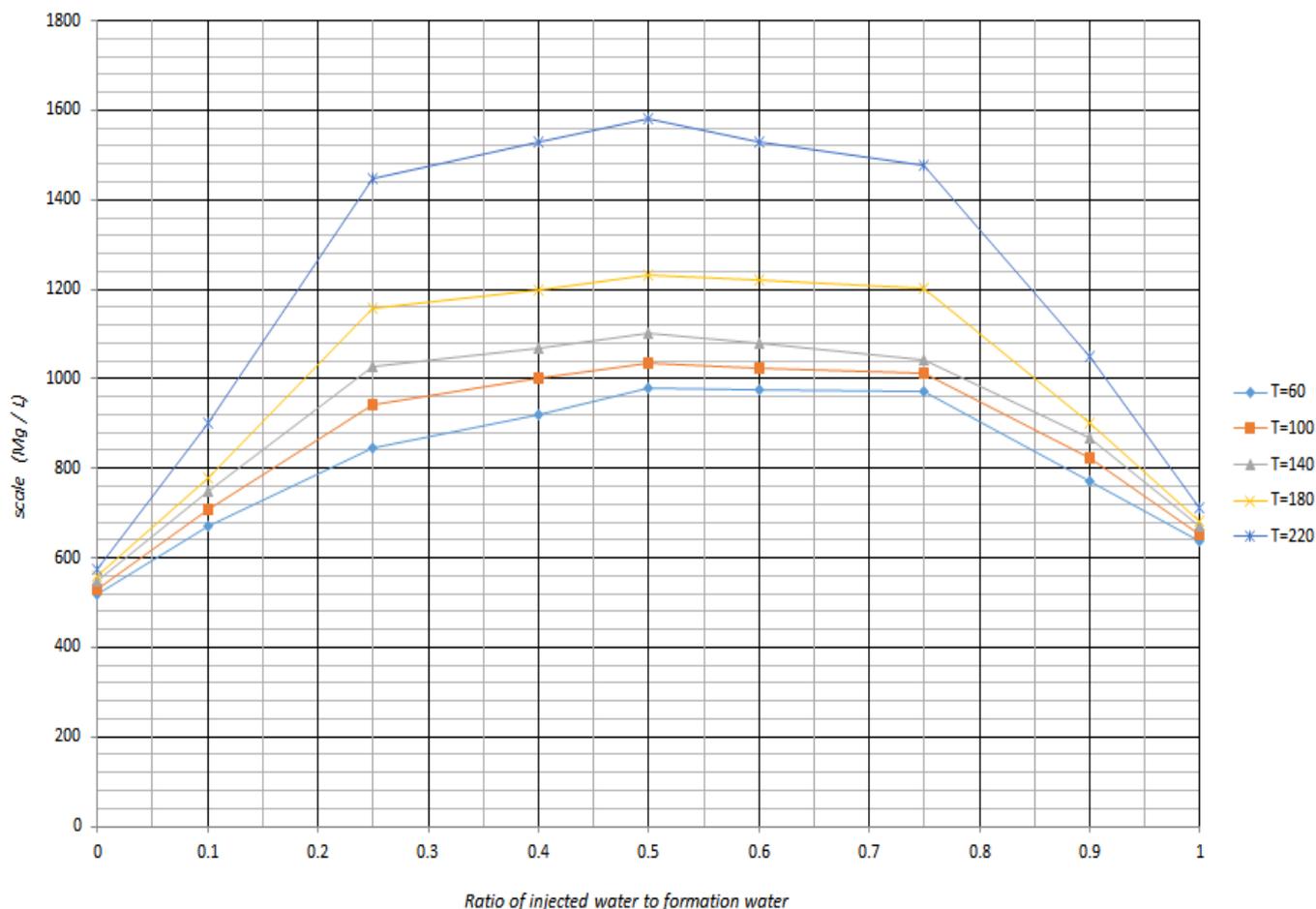
Fig. 1- Effect of temperature on total scale formation

Fig. 1 represents the effect of temperature variations on total scale formation where the other parameters are fixed. As it is clear by increasing temperature the amount of scale increases and the maximum scale formation is observed at mixing ratio of 50:50. Another point is that, although the temperature raising intervals are fixed (50 °C) but the precipitated scales increase rapidly at higher temperatures. So two important results are concluded by this analysis; it can be recommended for scale formation control lowering the temperature and trying to change the mixing ratio of injection water to formation water by changing the injection rate in field.

3- 1- 2- Pressure effect on scale formation
The next sensitive analysis is to consider the effect of pressure changes at constant temperature. Table 4 shows the selected thermodynamics situations to simulate scale formation. Again 5 different mixing ratios of injected water and reservoir water have been considered in Table 3.

Fig. 2 shows the effect of pressure on total scale formation where the other parameters are constant. It can be observed that by increasing pressure the amount of scale formation decreases and the maximum scale amount at low pressures occur at mixing ratio of 50:50. But at higher pressures the critical condition happens at mixing ratio of 75% (injection water) to 25% (reservoir water). Here it can be seen that the precipitated scales decrease more rapidly at lower pressures and the differences are lower at higher pressures. So raising the injection pressure is useful for scale formation control. Also, the mixing ratio of injection water should be lowered to less than 75% at high pressures to improve this remedy.

3- 1- 3- Scaling confirmation parameters
Now, the scale tendency and scaling index are measured to ensuring the scale formation. Table 5 shows the calculated amounts of these two parameters for all 10 cases in previous sections.

Table 4- Thermodynamics specifications of pressure-sensitive analysis

Case no.	Temperature in ºC (Equivalent amount in ºF)	Pressure in Pa (Equivalent amount in psia)
1	37.7 ºC (100 ºF) {wellhead temp.}	13.8×10^6 Pa (2000 psia)
2	54.4 ºC (130 ºF)	13.8×10^6 Pa (2000 psia)
3	71.1 ºC (160 ºF)	13.8×10^6 Pa (2000 psia)
4	87.7 ºC (190 ºF)	13.8×10^6 Pa (2000 psia)
5	104.4 ºC (220 ºF) {reservoir temp.}	13.8×10^6 Pa (2000 psia)

Fig. 2- Effect of pressure on total scale formation

Table 5- Scale Tendency and scale index in different conditions

Temperature, ºC (ºF)	37.7 ºC (100 ºF)	54.4 ºC (130 ºF)	71.1 ºC (160 ºF)	87.7 ºC (190 ºF)	104.4 ºC (220 ºF)	65.5 ºC (150 ºF)	65.5 ºC (150 ºF)	65.5 ºC (150 ºF)	65.5 ºC (150 ºF)	65.5 ºC (150 ºF)
Pressure, Pa (psia)	$13.8×10^6$ Pa (2000 psia)	$13.8×10^6$ Pa (2000 psia)	$13.8×10^6$ Pa (2000 psia)	$13.8×10^6$ Pa (2000 psia)	$13.8×10^6$ Pa (2000 psia)	$101×10^6$ Pa (14.7 psia)	$6.9×10^6$ Pa (1000 psia)	$13.8×10^6$ Pa (2000 psia)	$20.7×10^6$ Pa (3000 psia)	$31.1×10^6$ Pa (4500 psia)
Scale tendency	10.87	8.61	11.23	7.85	9.69	3.57	9.84	3.93	13.19	4.32
Scaling index	0.97	0.78	1.01	0.71	0.84	0.62	0.89	0.67	1.16	0.71

Table 6- Thermodynamics conditions of laboratory test cases

Case no.	Temperature in ºC (Equivalent amount in ºF)	Pressure in Pa (Equivalent amount in psia)
1	54.4 ºC (130 ºF)	$13.8×10^6$ Pa (2000 psia)
2	65.5 ºC (150 ºF)	$20.7×10^6$ Pa (3000 psia)
3	104.4 ºC (220 ºF)	$13.8×10^6$ Pa (2000 psia)

Table 7- Scale amounts by compatibility lab tests

Case no.	$CaCO_3$ mass by software simulation (mg/l)	$CaCO_3$ mass by lab testing (mg/l)	$CaSO_4$ mass by software simulation (mg/l)	$CaSO_4$ mass by lab testing (mg/l)
1	287	295	728	740
2	327	335	883	875
3	648	630	934	920

As Table 5 represents all 10 cases have ST>1 and SI>0, so it confirms that all simulated points of previous stage have the scale formation potential.

3- 2- Scale formation evaluation by lab testing

As mentioned in section 2, three points are randomly chosen for laboratory experiments to check the validity of software results. Table 6 shows the selected point's conditions.

The considered time for this test was 5 days. After this time the generated mass are analyzed by SEM (EDX) tests to find the type and mass of the precipitated scales in stage 2.6. Fig. 3 shows the analysis results. Graphs A and C confirm the existence of sulfate and calcium minerals at approximately equivalent amounts and Graph B confirms the sulfate base crystal and some percentages of calcium content.

Table 7 compares the calculated amount of scales at the selected points to the lab test result.

Based on the above table, the difference between compatibility lab testing results and simulations is less than 3%. So the accuracy of modeling can be considered acceptable for other simulated points and ensures the effect of deposited scale on fluid flow in porous media.

3- 3- Core flooding tests

This test helps us to recognize the rising trend of injection pressure during disposal water injection operation due to scale deposition at bottom of the well in near wellbore region as illustrated in previous section. The core sample is housed inside a rubber sleeve in core holder of experimental system. And Fig. 4 shows the Core holder device. The test setup is shown Fig. 5. [4]

A			B			C		
Element	*weight%*	*Area%*	*Element*	*weight %*	*Area %*	*Element*	*weight %*	*Area %*
C	*14.61*	*12.23*	*C*	*3.37*	*0.18*	*C*	*10.12*	*4.26*
O	*35.21*	*36.45*	*O*	*42.36*	*43.01*	*O*	*28.42*	*29.89*
N	*2.65*	*0.98*	*N*	*3.50*	*1.03*	*Mg*	*3.20*	*1.50*
Al	*0.26*	*0.12*	*Al*	*0.32*	*0.17*	*Al*	*0.29*	*0.10*
Si	*2.71*	*0.12*	*Si*	*3.43*	*0.29*	*Si*	*2.23*	*2.40*
S	*17.37*	*22.18*	*S*	*16.03*	*21.37*	*S*	*22.01*	*23.30*
Ca	*24.03*	*26.37*	*Ca*	*27.58*	*32.14*	*Ca*	*26.30*	*31.60*
Fe	*1.60*	*0.75*	*Fe*	*2.80*	*1.64*	*Fe*	*2.19*	*2.35*
P	*1.18*	*0.70*	*P*	*0.15*	*0.06*	*Sr*	*3.10*	*2.50*
Cl	*0.38*	*0.10*	*Cl*	*0.46*	*0.11*	*Ba*	*2.14*	*2.10*
	100.00	*100.00*		*100.00*	*100.00*		*100.00*	*100.00*

Fig. 3- Scale evaluation by SEM test

Fig. 4- Core holder photo

Table 8 shows the core samples specifications. This experiment has done twice to ensure the final results.

In this test, the rock sample is saturated with reservoir and injection process is continued at reservoir condition (Temperature: 104.4°C (220 °F), Pressure: 27.5×10⁶ Pa (4000 psia)) by injection rate of 5 cm³/min. Then injection of brine will be started to find its damage effect on rock and sketch P vs. PV (pressure vs. injected pore volume) and by linear flow of Darcy's law we got K vs. PV (permeability vs. injected pore volume).

According to the Darcy's law:

$$q = \frac{k.A_b.\varphi.\Delta p}{\mu.L} \tag{3}$$

In this equation, q is the injection rate, φ is Porosity, μ is fluid viscosity, A_b is the cross-sectional area of the rock, K is absolute permeability of the rock, L is core sample length and Δp is the pressure difference through the rock.

So it is possible to find rock's permeability by inserting pressure difference in Darcy [15].
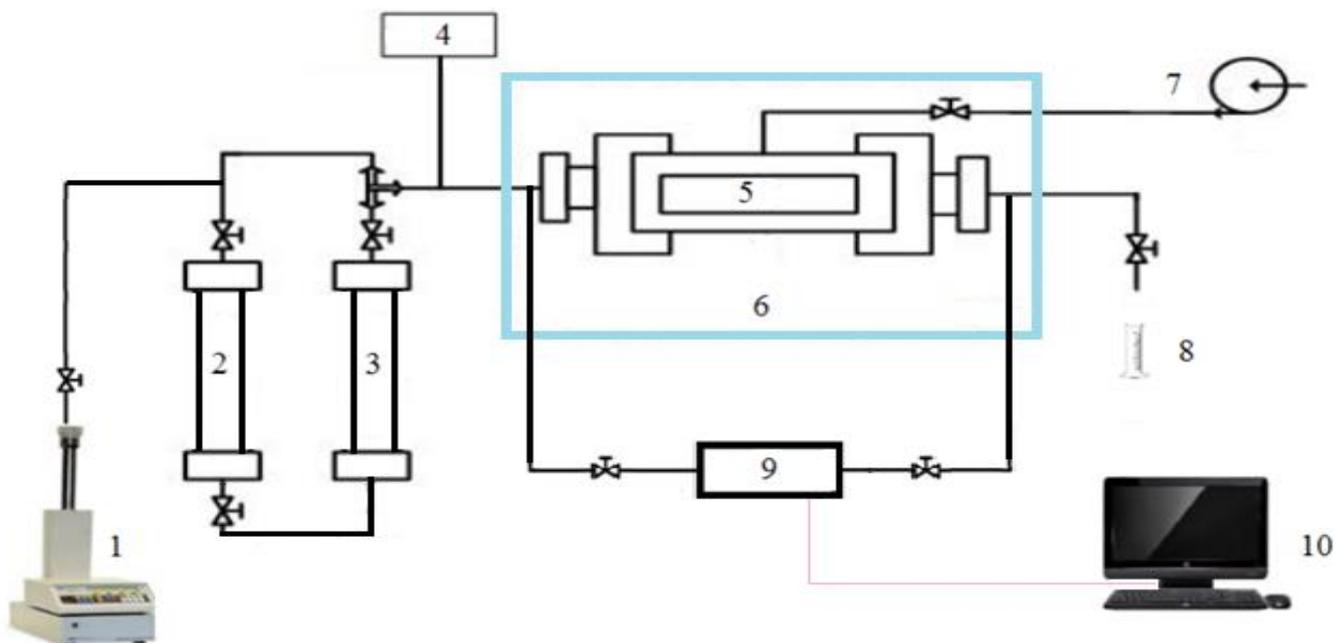
Fig. 5- Typical graph of core flooding test setup, 1: HP ISCO syringe pump; 2: HP brine transfer cell; 3: HP formation water transfer cell; 4: Pressure transducer; 5: Core holder; 6: Oven; 7: Overburden pump; 8: Sample valve; 9: High differential pressure; 10: Data acquisition system

Table 8- Specification of reservoir rock sample

Core sample	1	2
Length (cm)	5.681	5.692
Diameter (cm)	3.237	3.237
Porosity (%)	10.82	10.989
Pore volume (cm3)	5.056	5.045
Temperature (ºC (ºF))	93.3 (200)	93.3 (200)
Pressure (Pa (psi))	101.3×103 Pa (14.7 psia)	101.3×103 Pa (14.7 psia)
Injection rate (cc/hr)	1	1
Lithology	Sandstone (66%) & Limestone (34%)	Sandstone (72%) & Limestone (28%)

Figs. 6 to 9 represent the core-flooding test results for both samples. The same as predictions, permeability amount reduces as injection process goes on. Also, injection pressure rises during the test. The most amount of fluid flow decline and pressure raise happens at first steps of fluid injection in both core flooding tests. The core flooding tests prove the precipitation of inorganic scales and consequently their deposition in porous media of core samples.

So the third step of modeling result confirmation has been done, and the effect of mineral scale formation on fluid flow condition of reservoir rock is clearly observable.
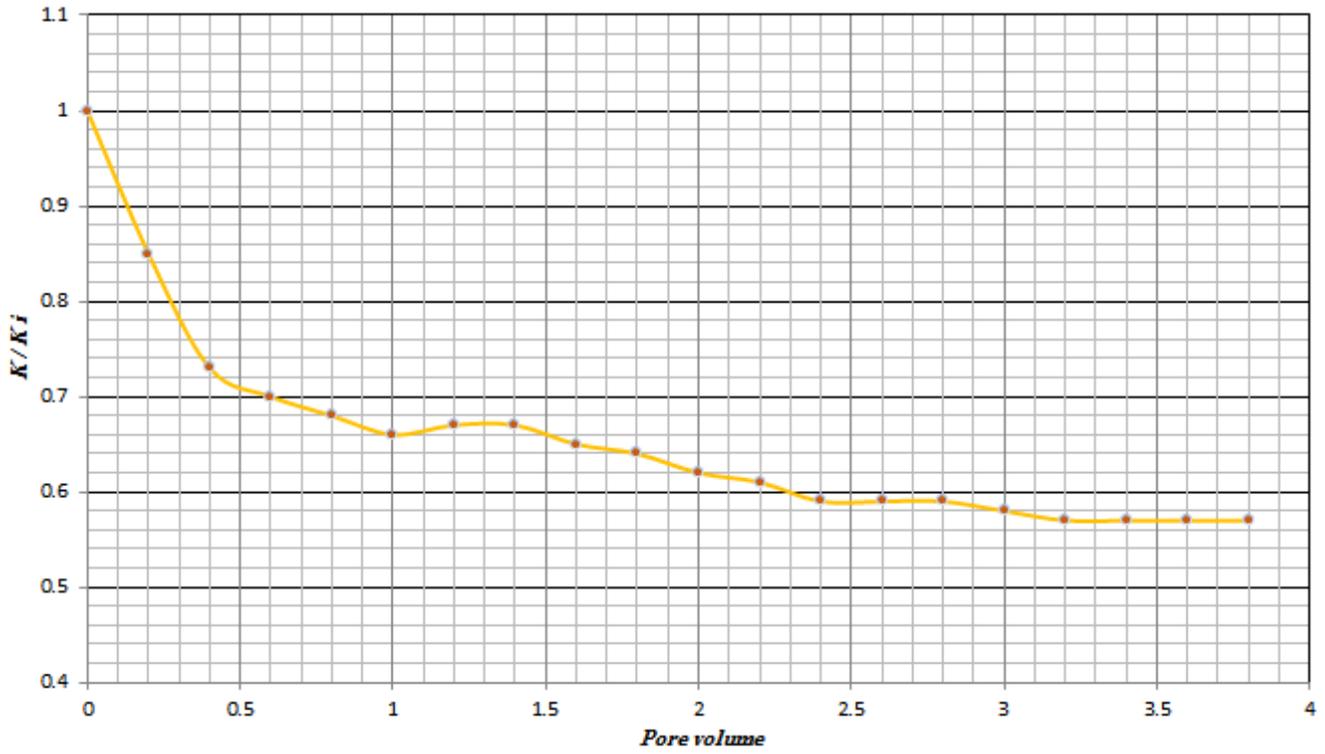
Fig.6- Permeability variation vs. injected water volume for core flooding test # 1
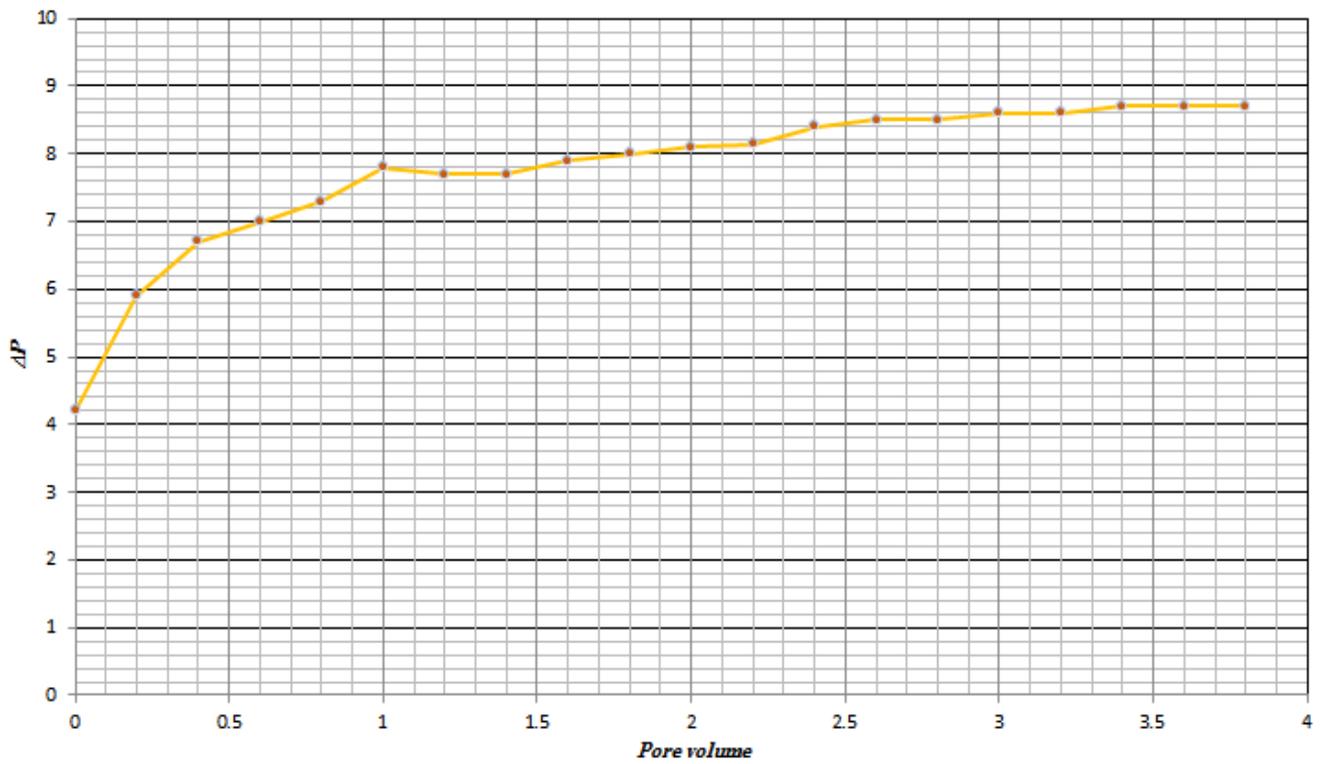
Fig. 7- Pressure drop vs. injected water volume for core flooding test # 1
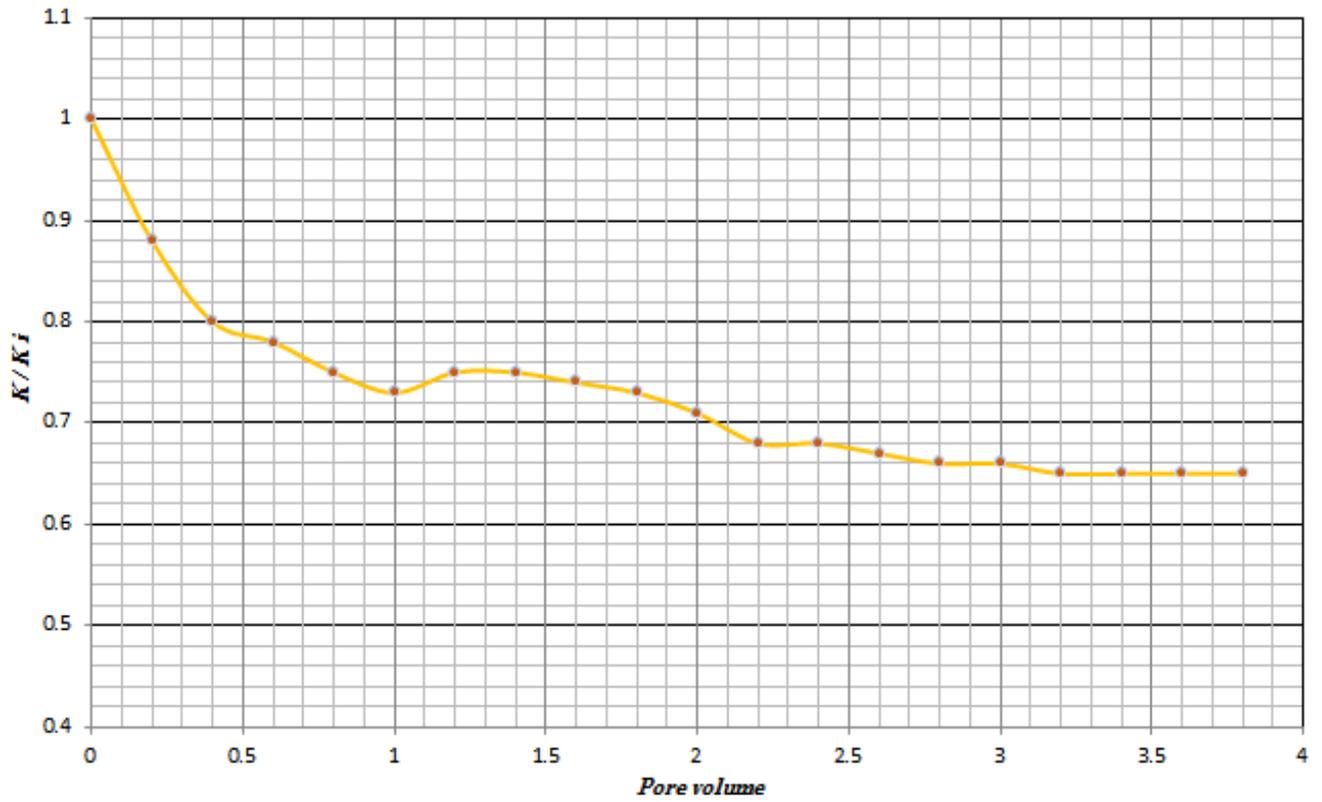
Fig. 8- Permeability variation vs. injected water volume for core flooding test # 2
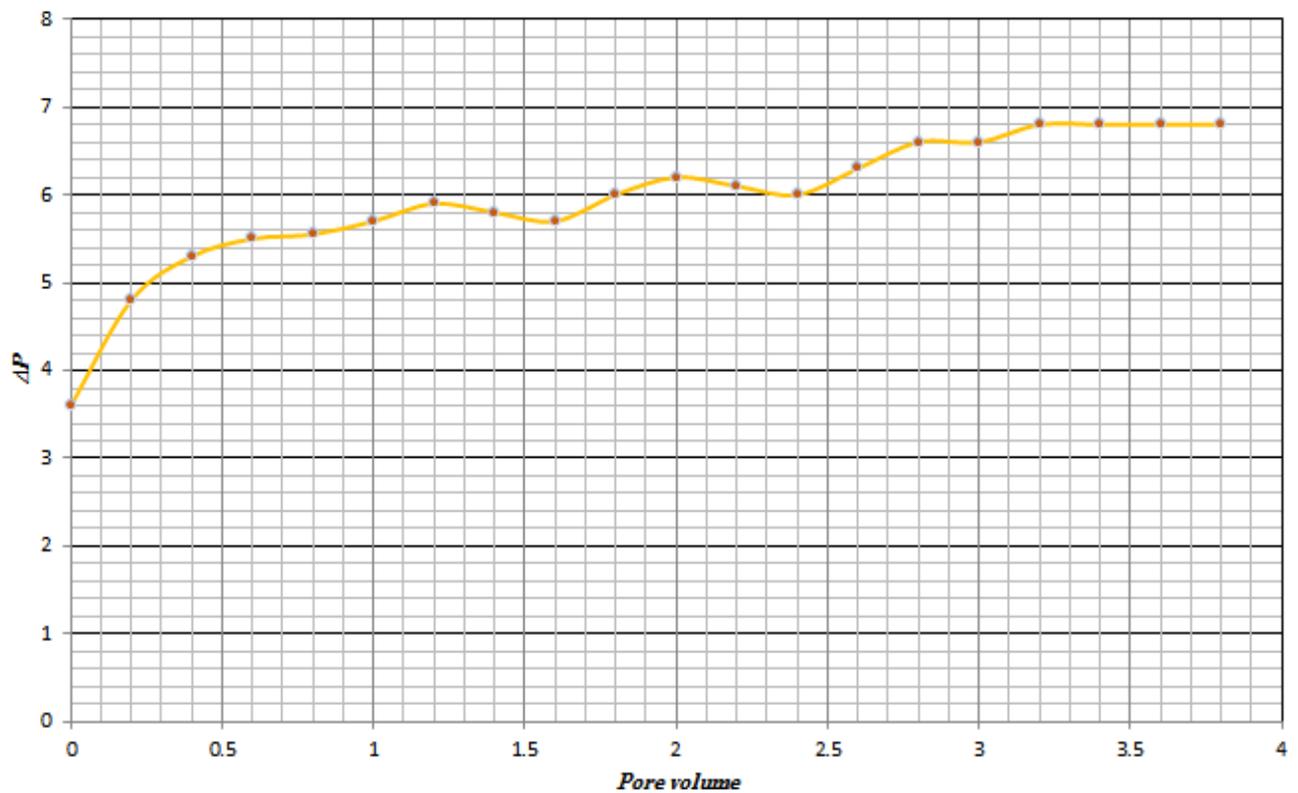
Fig. 9- Pressure drop vs. injected water volume for core flooding test # 2

4- Conclusions

Based on the laboratory experiments and modeling results, $CaSO_4$ and $CaCO_3$ are the dominant inorganic scales in the studied Iranian south-western oil field by water injection operation.

Based on simulation and lab test results, total scale formation increases by rising system temperature. The maximum scale precipitates at fluid mixing ratios of 50% injection water and 50% reservoir formation water.

Also, simulation and lab test results show that total scale formation decreases by increasing system pressure. The maximum scale precipitates at fluid mixing ratios of 75% injection water and 25% reservoir formation water, for high-pressure conditions; and 50:50 for low-pressure conditions.

Core flooding test graphs represent that a sharp decline happens at the primary 20% of injected fluid. So this is the critical section of scaling control. Managing thermodynamics conditions, mixing ratio and water injection rate can help us to control the type and mass of scale formation in water injection process.

Nomenclature

φ: Porosity

Q: activity coefficient

q: injection rate

PV: pore volume

μ: fluid viscosity

A_b: cross-sectional area of the rock

K: Absolute permeability of the rock

ST: scale tendency index

SI: scaling index

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