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Screening Produced Water Disposal Challenges in an Oilfield: Scale Formation and Injectivity Impairment

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Highlights

- Temperature change has the primary effect on scale formation. At higher temperatures, calcium carbonate deposition increases because the solubility of CaCO_3 decreases with increasing the temperature;
- The scale deposition of calcium carbonate and iron carbonate increases by pressure drop. Pressure drop increases CO_2 partial pressure and raises the scale deposition of calcium and iron carbonate;
- The incompatibility between formation water and desalting unit water results in the formation of CaCO_3 and FeCO_3 as the dominant scales in disposal wells.

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Abstract


Sarvestan and Saadatabad oilfields produce more than 140 bbl/day of wastewater due to oil processing. Due to environmental issues, the produced water is injected into a disposal well through a pipeline with a diameter of 8 inch and a length of 5 km. Formation of inorganic scale may accelerate the need for frequent reservoir acid stimulation, restrict flow path, and generally add unpredicted costs for water injection operations. This study predicts scaling tendency and examines scale precipitation at different pressures, temperature, and mixing ratios of injection wastewater with formation water in Sarvestan and Saadatabad oilfields. The experimentally measured chemical analysis of the injection water and formation water was used to estimate the amount, type, and composition of scale due to mixing and changes in thermodynamic conditions. Scaling tendency values for eight types of scale, namely CaCO_3 (calcite), CaSO_4 (anhydrite), $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ (gypsum), FeCO_3 (siderite), $\text{Fe}(\text{OH})_2$ (amorphous), NaCl (halite), $\text{Mg}(\text{OH})_2$ (pyrochroite), and KCl (sylvite), were investigated by commercial software packages OLI ScaleChem and StimCADE. The results show that the significant scales are CaCO_3 and FeCO_3 formed in Sarvestan and Saadatabad oilfields. The formation of these scales can lead to severe problems, such as disrupting equipment and decreasing production; thus, it is necessary to predict all types of scales before forming. It allows design and planning for chemical inhibitor treatment and prediction of injectivity problems and acid stimulation.

Keywords: CaCO_3 ; FeCO_3 ; Produced water; Scaling tendency; Sarvestan and Saadatabad oilfields.

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1. Introduction

Due to the high volume of produced water from oil and gas reservoirs and subsequent environmental effects of such waters, it is required to dispose of and inject this water into underground formations. Produced water generally contains hazardous materials such as oil droplets and chemicals that require safe treatment and disposal. Here, dispersed oil, aromatic hydrocarbons, alkylphenols (AP), heavy metals, and naturally occurring radioactive material (NORM) are of particular environmental concern (Bakke et al., 2013). In addition, the composition of the produced water varies during reservoir life and needs careful monitoring for possible challenges. Underground porous formations are good candidates that have been widely used for the reinjection of producer water. Both underground aquifers and oil and gas reservoirs have been used for produced water reinjection and disposal (Tale et al., 2020).

One of the main challenges of these operations is increasing the probability of scale formation due to the change of the thermodynamic equilibrium of the reservoir water because of its chemical and physical incompatibility with that of injected water. The formation of these scales restricts the flow of fluid in the porous environment of the reservoir and the plant and ultimately reduces the oil production rate in the well. In addition, the transfer and accumulation of these scales in the surface and under the subsurface facilities corrode these facilities and damage production and injection well (Kalantariasl et al., 2019).

Scale is often defined as the precipitation from aqueous solution with inorganic sediments, and scale deposition is one of the most problematic issues in different stages of oil field productions (Shabani et al., 2019; Ghasemian et al., 2019; Abouie et al., 2019; Shabani et al., 2019; ShahzadKamal et al., 2018). Examples are water injection for pressure maintenance or enhanced oil recovery; oil production, gathering, and transportation; warming treatment; demulsification; crude oil dehydration and desalting; and produced water disposal in water disposal wells. Meanwhile, the scale appears on the downhole tools, oil well casing, oil pipelines, and other production equipment (Hussein et al., 2017; Luo et al., 2015).

Very complicated factors are involved in the formation of scales. Scale formation can be summarized in three steps (Jack and Donald, 1976):

- 1) Super-saturation of solution;
- 2) Nuclear gathering;
- 3) Crystal growth.

Settling of scale is a complex phenomenon of crystallization. The formation speed of the first layer and the growth of subsequent layers depend on many interactions, including nuclear accumulation, molecular penetration, chemical reactions, and molecular arrangement of the crystal lattice network.

Most mineral deposits have a reversible solubility, that is, their solubility decreases with increasing temperature. Thus, when the supersaturation solution is in contact with the heat transfer surfaces, solids start to settle down because of their low solubility. When the supersaturation and nuclear accumulation are started, the conditions are desirable for crystal growth and ideal for scale formation. Compounds that dissolve in water (calcium carbonate and calcium sulfate) may be deposited with changes in conditions such as pressure drop, temperature variations, flow changes, incompatibility, contamination,

and pH (Jack and Donald, 1976). It is worth mentioning that the solubility of a given solute in a given solvent usually depends on temperature. Many salts show an increase in solubility with temperature. Some salts become less soluble in water as the temperature rises. This temperature dependence is sometimes referred to as retrograde or inverse solubility and exists when a salt's dissolution is exothermic, which can be explained according to Le Chatelier's principle: extra heat causes the equilibrium for an exothermic process to shift toward the reactants.

The most important factors controlling the first and second steps are time, temperature, pressure, pH, environmental factors, and particle size. The critical factors controlling the third step are the fluid flow rate, temperature, water composition, molecular and atomic arrangement, molecular penetration, energy activation, and molecular network building compatibility (Jack and Donald, 1976).

The critical requirements for scale settling are presented in Figure 1.

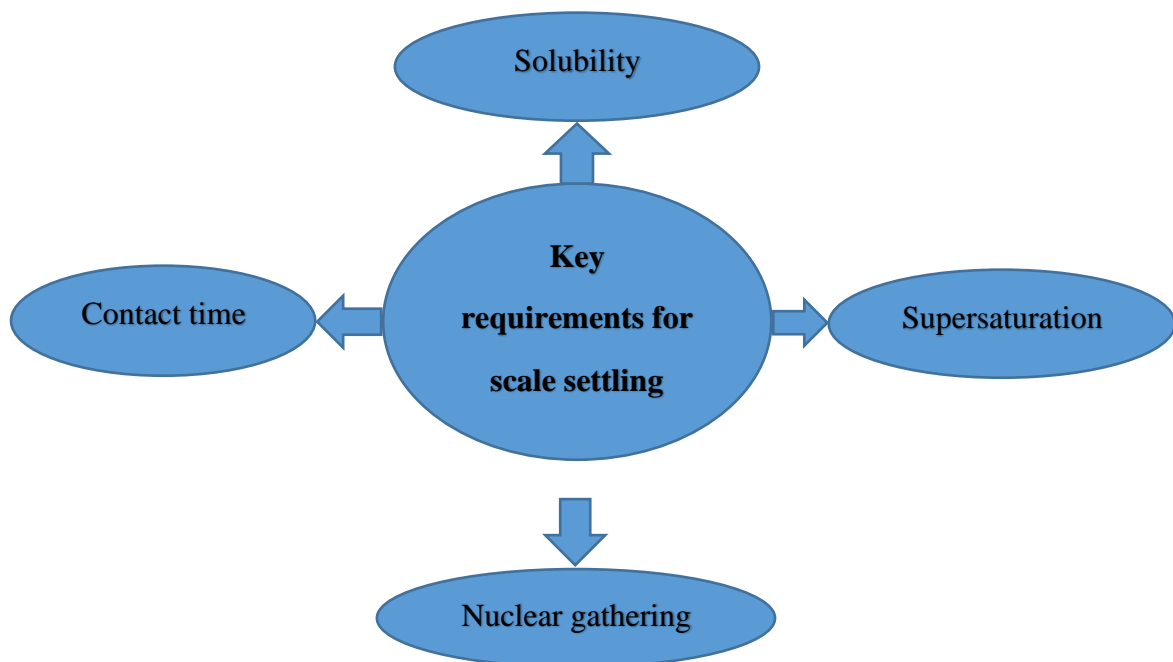


Figure 1

The primary factors affecting the scale formation.

2. Solubility and supersaturation conditions

The main reason for the settling of scale is the supersaturation of the solution. A scale will be formed if the soluble material in the solution increases its solubility (called secondary factors). These secondary factors are the pressure variations, temperature variations, change in pH, fluid flow speed variation, and mixing of two incompatible types of water (Jack and Donald, 1976).

2.1. Nuclear gathering

Although changes in temperature and pressure can cause scale formation, gas exhaust, pH changes, or mixing of incompatible waters, many supersaturated water samples, which tend to form scale, do not always deposit. A possible reason is that scale precipitation needs attractive intermolecular forces for accumulation and further growth. In many cases, the conditions are against attraction and further growth. Here, a difference between scale precipitation and deposition must be considered. The first stage of forming a scale in a saturated solution is forming atomic groups called homogeneous nuclear gatherings. In fact, in this case, the pair of single crystals forming ions in the supersaturated solution

causes the growth of the precipitate, and then the grainy crystals formed by the adsorption of the ions grow. Crystals also tend to grow with boundaries with heterogeneous fluid in nuclear accumulation. In a heterogeneous nuclear accumulation, scale deposits on pre-existing surface areas, such as the roughness of the pipe surface, the intermediate pipe lattices, even at connecting points, or the cracks in the extraction pipe and pipelines. Extreme turbulence can also accelerate scale formation. Therefore, scale accumulation can occur at boiling point pressure, which explains the rapid scale formation in the underground well completion facilities. Chemical inhibitors are used to prevent the phenomena of nuclear accumulation. These inhibitors interfere with the nuclei created, disrupt the growth stages of scale formation, and slow down the rate of growth to zero (Jack and Donald 1976; Crabtree et al., 1999).

2.2. Contact time

The solution and the nuclear accumulation points should have a proper contact time to form scale after the supersaturation conditions and form a nuclear gathering. Usually, a longer contact time with the solution causes more scales to form. This time depending on the degree of supersaturation, scales, type and number of accumulation points, temperature, pressure, turbulence, and other environmental factors varies from several seconds to several years (Moghadasi et al., 2003). However, minimizing contact time may reduce scale deposition by higher velocity. In addition, the modification of surface, if possible, can be a practical method since reducing contact time may not be applicable in many cases.

Table 1 lists a typical analysis of scales found in the Iranian offshore and onshore oilfields.

Table 1

The typical scales in Iranian oilfields (Amiri and Moghadasi, 2013).

Area	Formation	Major scale
The Persian Gulf (Siri-C)	Mishrif	SrSO ₄
The Persian Gulf (Siri-D)	Mishrif	SrSO ₄
The Persian Gulf (Siri-E)	Mishrif	FeCO ₃
The Persian Gulf (Nosrat)	Mishrif	SrSO ₄
Onshore field (Ahwaz)	Bangestan	CaCO ₃
Onshore field (Aghajari)	Bangestan	CaCO ₃
Onshore field (Haftkel)	Asmari	FeCO ₃
Onshore field (Cheshmeh-Khosh)	Asmari	FeCO ₃
Onshore field (Sarvestan and Saadatabad)	Sarvak	CaCO ₃

Calcium carbonate (calcite) and iron carbonate (siderite) are often found in Sarvestan and Saadatabad oilfields. However, calcite is most stable in oilfield conditions, so it is the most common form of calcium carbonate encountered in the disposal wells and surface facilities (Amiri and Moghadasi, 2012). The deposition of the CaCO₃ scale is obtained from the calcium carbonate deposition according to the following equation:



The calcium carbonate scale can also be formed by the combination of calcium and bicarbonate ions, and this reaction is the most crucial factor in calcium carbonate scale deposition in oilfield operations (Moghadasi et al., 2004).

Iron carbonate (FeCO_3) is one of the main corrosion products in the CO_2 corrosion process. If the concentration of the product of ferrous ion (Fe^{2+}) and carbonate ion (CO_3^{2-}) exceeds the solid solubility according to the reaction, solid FeCO_3 can be formed (Amiri et al., 2013):



In this paper, scaling tendency and scale precipitation values for eight types of scales, namely CaCO_3 (calcite), CaSO_4 (anhydrite), $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ (gypsum), FeCO_3 (siderite), $\text{Fe}(\text{OH})_2$ (amorphous), NaCl (halite), $\text{Mg}(\text{OH})_2$ (pyrochroite), and KCl (sylvite), are investigated by OLIScale CHEM and StimCADE software. As the results show, only CaCO_3 and FeCO_3 scales are formed, and their values are examined by both software packages shown in the results section. Therefore, it is necessary to inject suitable inhibitors in this oil field; otherwise, serious problems will arise for the facility and injection well. It is worth mentioning that other organic scales such as wax and asphaltene are also prevalent in many oilfields, which are not considered in this study.

3. Introducing Sarvestan and Saadatabad oilfields

The operative area of Sarvestan and Saadatabad is located 120 km southwest of Shiraz and near the city of Sarvestan. The crude oil of this complex is supplied from Sarvestan and Saadatabad oil wells. In this area, the oil output from the Sarvestan wells enters the Sarvestan high-pressure (HP) separator, and the oil output from the Saadatabad wells enters the Saadatabad high-pressure separator. Crude oil of Sarvestan and Saadatabad high-pressure separators passes through the medium-pressure (MP) and low-pressure (LP) separators and then passes through the desalination unit. In the desalination unit, a freshwater stream (washing water) is injected into the oil flow section to dissolve and dilute salts in the oil stream. Then, an electrical field is applied to separate oil and water. The output of this unit is clean oil and salty water. Here, saline water is transferred to a pipeline for disposal into a water disposal well by a pump and pressure of about 500 psia. On average, 140 bbl/day of water is injected into these oilfields, and so far, about 60500 bbl of water have been injected into a water disposal well due to environmental concerns and regulations. Figure 2 shows the location of the Sarvestan and Saadatabad oilfields.



Figure 2

The location of Sarvestan and Saadatabad oilfields.

4. Water analysis

To obtain an initial scale potential condition, we prepared two samples of produced water of desalting unit and formation water for water composition analysis with the composition listed in Table 2.

Table 2

Water analysis of the desalting unit and formation water from Sarvestan and Saadatabad oilfields.

Ions (mg/l)	Formation water	Desalting unit
Cl ⁻	119650	10813
SO ₄ ⁻²	330	30
HCO ₃ ⁻	970	488
Mg ⁺²	3300	207
Ca ⁺²	6135	477
Na ⁺	64741	6264
K ⁺	64741	6264
Ba ⁺²	-	-
Fe ⁺²	65	0.46
Sr ⁺²	-	-
Li ⁺	-	-
TDS	259932	24543.46
pH	7.65	6.5
CO ₂	-	-
H ₂ S	-	-
SG	1.085	1.015
Conductivity (μs/cm)	386000	26000
Flow rate (bbl/day)	-	140

5. Scaling tendency prediction

The scaling tendency is defined as the ratio of the activity product of an equilibrium equation to the solubility product for the same equation. We define the activity product as Q , so we have:

$$\text{Scale Tendency (ST)} = Q/K_{SP} \quad (3)$$

As an example, consider the equilibrium for calcite solubility. The equilibrium expression for CaCO₃ is given by:



The activity product, Q , is defined as:

$$Q = (a_{\text{Ca}^{++}}) (a_{\text{CO}_3^{--}}) \quad (5)$$

where a_i is the activity of the species.

$$a_i = \gamma_i \times m_i \quad (6)$$

where, γ_i is the activity coefficient for species i , and m_i indicates the molal concentration.

The solubility product, K_{sp} , is a thermodynamic quantity and is a function of temperature and pressure although, in most cases, the pressure functionality for solids can be ignored. OLI ScaleChem and StimCADE software have stored the K_{sp} for all solids used in the chemistry model. When the ratio Q/K_{sp}

is greater than 1.0, the solid forms. When the ratio is lower than 1.0, the solid has a slight tendency to form.

6. Results

6.1. Effect of temperature on scaling tendency and scale precipitation

An increase in the temperature enlarges the thermal energy of the molecules in the equilibrium mixture and the molecular collisions, raising the rate of the reactions. However, the increase in these parameters is not the same, and various experiments show that the increase in temperature raises the rate of endothermic reaction more. Thus, in the new equilibrium, the concentrations of the materials in the equilibrium change.

In this section, we examine the effect of temperature on the formation of different scales at constant pressure. The temperature ranges from 80 to 200 °F at a constant pressure of 500 psia.

The CaCO_3 , CaSO_4 , $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$, FeCO_3 , $\text{Fe}(\text{OH})_2$, NaCl , $\text{Mg}(\text{OH})_2$, and KCl scaling tendency at different temperatures are shown in Figures 3 and 4.

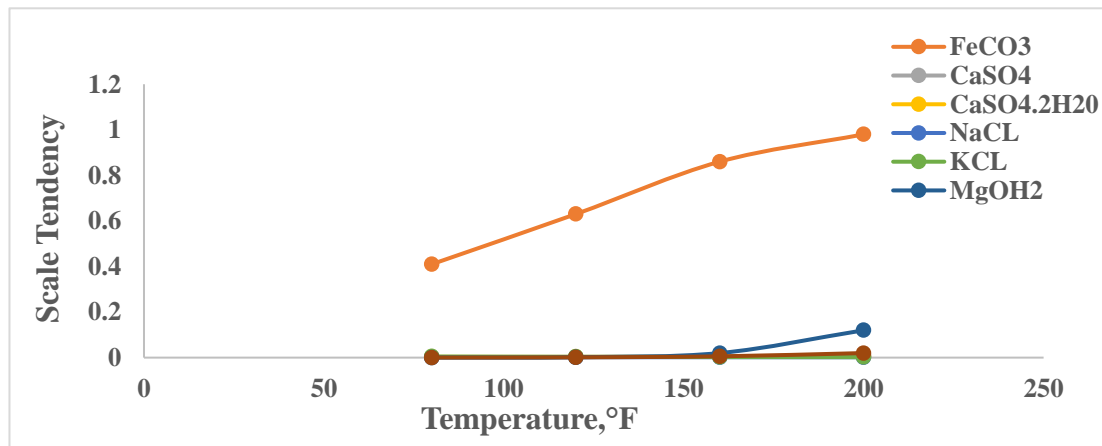


Figure 3

The prediction of scaling tendency versus temperature at a pressure of 500 psi by OLI ScaleChem software.

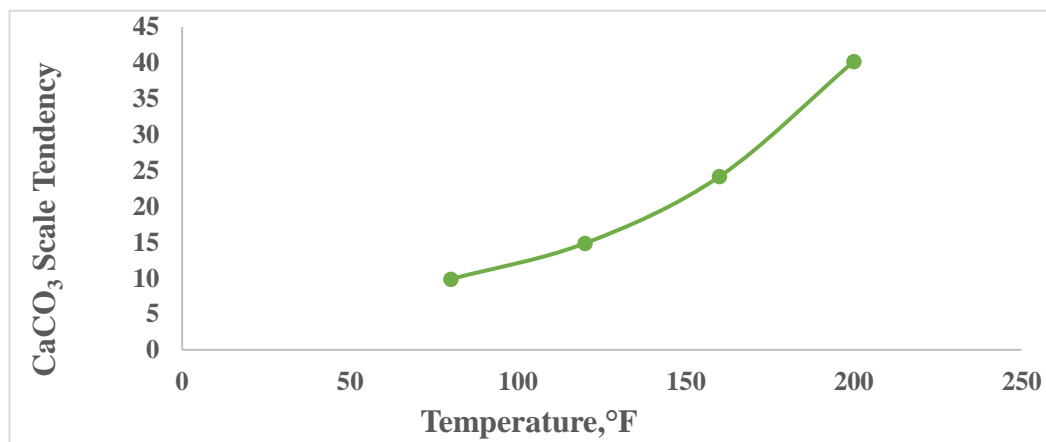


Figure 4

The prediction of CaCO_3 scaling tendency versus temperature at a pressure of 500 psi by OLI ScaleChem software.

As shown in Figure 3, the scaling tendency of FeCO_3 , CaSO_4 , $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$, $\text{Fe}(\text{OH})_2$, NaCl , $\text{Mg}(\text{OH})_2$, and KCl is lower than 1.0, so these scales cannot be formed. However, the scaling tendency of CaCO_3 is higher than 1.0, as shown in Figure 4; therefore, this scale can be formed, and the precipitation values of this scale are presented in Table 3 and Figure 5 by OLI ScaleChem and StimCADE software.

Table 3
CaCO₃ scaling tendency and scale precipitation.

Temperature (°F)	Pressure (psia)	OLI ScaleChem	OLI ScaleChem	StimCADE
		CaCO ₃ solid (mg/L)	CaCO ₃ scaling tendency	CaCO ₃ solid (mg/L)
80	500	86.16	9.85	91.772
120	500	130.33	14.86	122.254
160	500	180.54	24.16	157.081
200	500	229.24	40.21	191.962

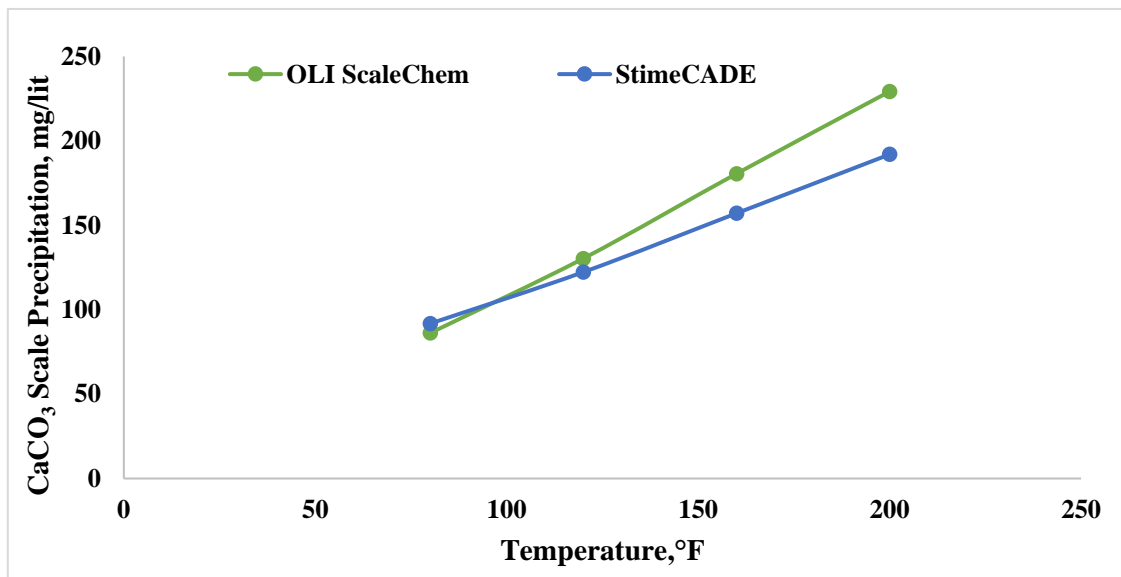


Figure 5

CaCO₃ scale precipitation versus temperature at a pressure of 500 psi.

6.2. Effect of pressure on scaling tendency and scale precipitation

Raising the pressure increases the pressure applied to each composition. Increased pressure indicates that more particles enter the liquid. Therefore, raising pressure will increase the degree of solubility.

This section examines the effect of pressure on the formation of different scales at a constant temperature. The pressure ranges from 16 to 5000 psia at a constant temperature of 80 °F.

The CaCO₃, CaSO₄, CaSO₄·2H₂O, FeCO₃, Fe(OH)₂, NaCl, Mg(OH)₂, and KCl scaling tendency at different pressures are shown in Figures 6 and 7.

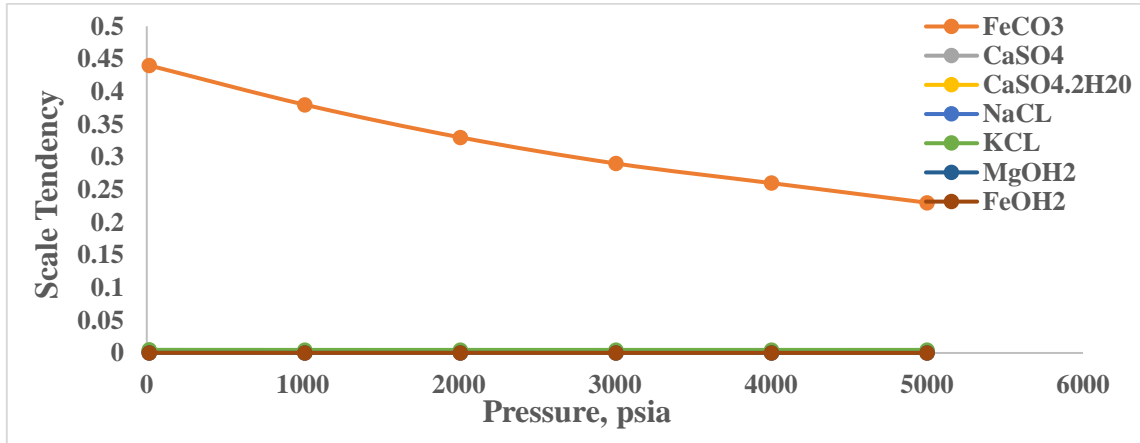


Figure 6

The prediction of scaling tendency versus pressure at a temperature of 80 °F by OLI ScaleChem software.

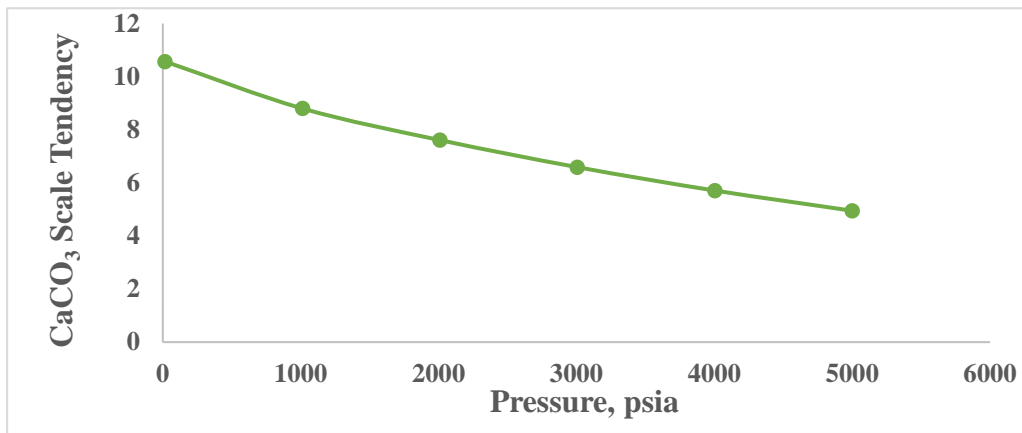


Figure 7

The prediction of CaCO₃ scaling tendency versus pressure at a temperature of 80 °F by OLI ScaleChem software.

As shown in Figure 6, the scaling tendency of FeCO₃, CaSO₄, CaSO₄.2H₂O, Fe(OH)₂, NaCl, Mg(OH)₂, and KCl is lower than 1.0, so these scales cannot be formed. Nevertheless, the scaling tendency of CaCO₃ is more than 1.0, as shown in Figure 7; therefore, this scale can be formed, and the precipitation values of this scale are presented in Table 4 and Figure 8 by OLI ScaleChem and StimCADE software.

Table 4
CaCO₃ scale tendency and scale precipitation by OLI ScaleChem.

Pressure (psia)	Temperature (°F)	OLI ScaleChem	OLI ScaleChem	StimCADE
		CaCO ₃ solid (mg/L)	CaCO ₃ scaling tendency	CaCO ₃ solid (mg/L)
16.00	80	89.79	10.57	91.772
1012.80	80	82.37	8.80	91.772
2009.60	80	75.21	7.61	91.772
3006.40	80	68.34	6.59	91.772
4003.20	80	61.78	5.71	91.772
5000.00	80	55.55	4.95	91.772

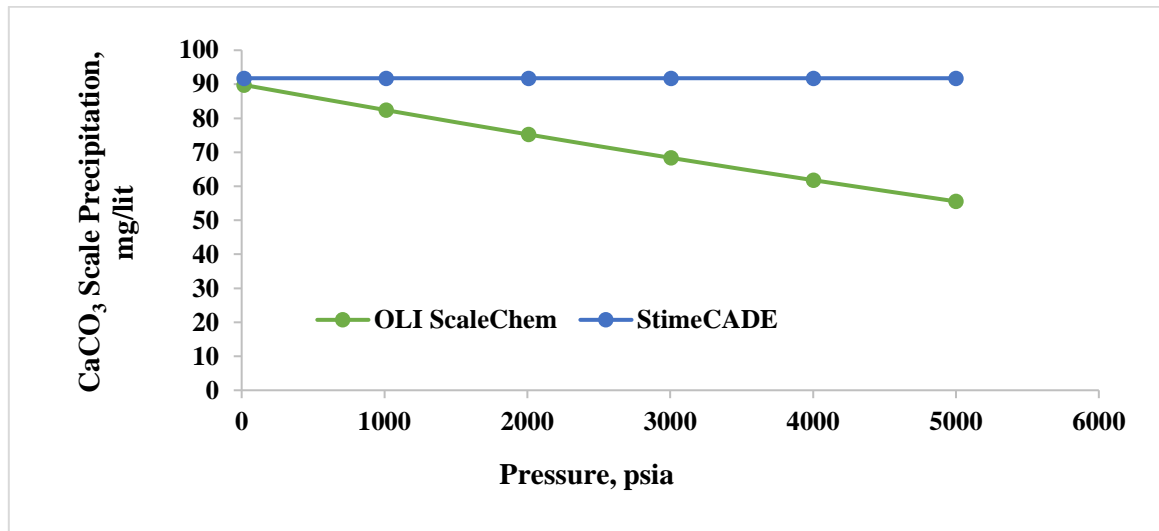


Figure 8

CaCO₃ scale precipitation versus pressure at a temperature of 80 °F.

6.3. Effect of mixing ratio on scaling tendency and scale precipitation

The effect of the mixing ratio depends on the number of ions in the injected water and formation water. This section examines the effect of the mixing ratio on the formation of different scales in reservoir conditions, that is a pressure of 4563 psia and a temperature of 182 °F.

The CaCO₃, CaSO₄, CaSO₄.2H₂O, FeCO₃, Fe(OH)₂, NaCl, Mg(OH)₂, and KCl scaling tendency at different mixing ratios are shown in Figures 9 and 10.

As shown in Figure 9, the scaling tendency of CaSO₄, CaSO₄.2H₂O, Fe(OH)₂, NaCl, Mg(OH)₂, and KCl is lower than 1.0, so these scales cannot be formed. Nevertheless, the scaling tendency of CaCO₃ and FeCO₃ is more than 1.0, as shown in Figure 10; therefore, these scales can be formed, and the precipitation values of these scales are listed in Tables 5 and 6.

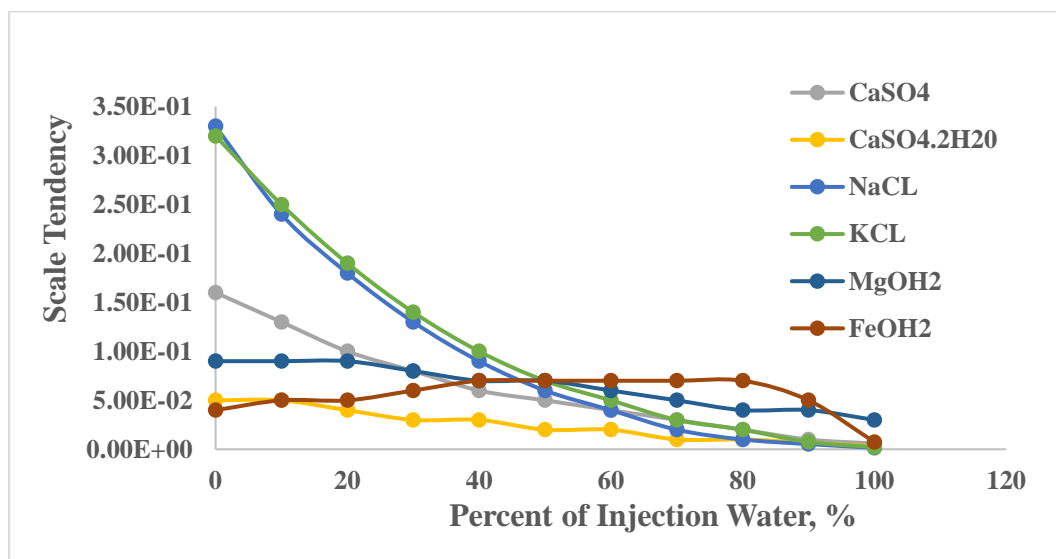
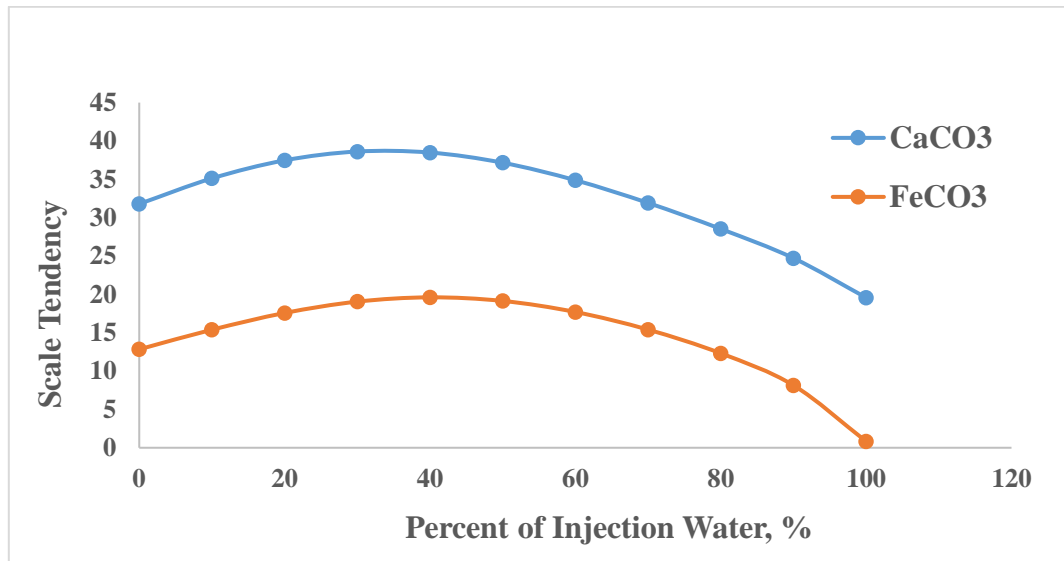


Figure 9

The prediction of scaling tendency versus mixing ratio at a temperature of 182 °F and a pressure of 4563 psia by OLI ScaleChem software.

**Figure 10**

The prediction of scaling tendency versus mixing ratio at a temperature of 182 °F and a pressure of 4563 psia by OLI ScaleChem software.

Table 5
CaCO₃ scaling tendency and scale precipitation.

Injection water (%)	Pressure (psia)	Temperature (°F)	OLI	OLI	StimCADE
			ScaleChem	ScaleChem	
			CaCO ₃ solid (mg/L)	CaCO ₃ scaling tendency	CaCO ₃ solid (mg/L)
100	4563	182	178.34	19.57	176.486
90	4563	182	225.04	24.72	227.328
80	4563	182	258.64	28.53	263.755
70	4563	182	287.82	31.92	295.650
60	4563	182	313.45	34.88	326.080
50	4563	182	334.81	37.16	355.761
40	4563	182	350.71	38.49	385.019
30	4563	182	360.01	38.62	414.025
20	4563	182	361.57	37.47	442.880
10	4563	182	354.65	35.12	471.647
0	4563	182	338.93	31.79	500.373

Table 6
FeCO₃ scaling tendency and scale precipitation.

Injection Water (%)	Pressure (psia)	Temperature (°F)	OLI	OLI	StimCADE
			ScaleChem	ScaleChem	
			FeCO ₃ solid (mg/L)	FeCO ₃ scaling tendency	FeCO ₃ solid (mg/L)
100	4563	182	0	0.83	0
90	4563	182	3.24	8.14	0
80	4563	182	7.85	12.31	6.359

Injection Water (%)	Pressure (psia)	Temperature (°F)	OLI	OLI	StimCADE
			ScaleChem	ScaleChem	FeCO ₃ solid (mg/L)
70	4563	182	15.34	15.40	14.980
60	4563	182	24.58	17.70	23.779
50	4563	182	33.45	19.14	32.692
40	4563	182	35.26	19.61	41.684
30	4563	182	32.7	19.05	50.733
20	4563	182	23.65	17.57	59.825
10	4563	182	15.1	15.39	68.948
0	4563	182	8.22	12.83	78.097

Figures 11 and 12 delineate the scale precipitation values of CaCO₃ and FeCO₃ by OLI ScaleChem and StimCADE software packages respectively.

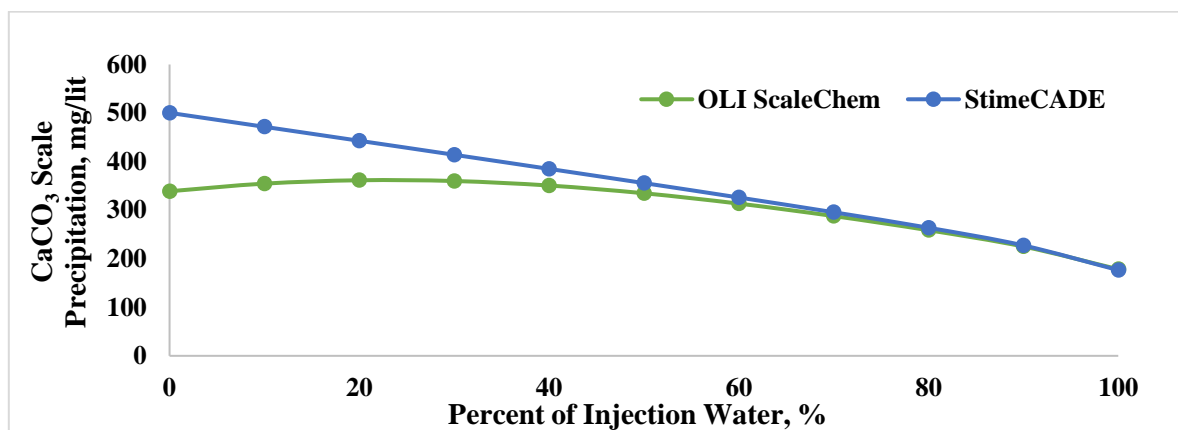


Figure 11

CaCO₃ scale precipitation versus the percentage of injection water at a temperature of 182 °F and a pressure of 4563 psia.

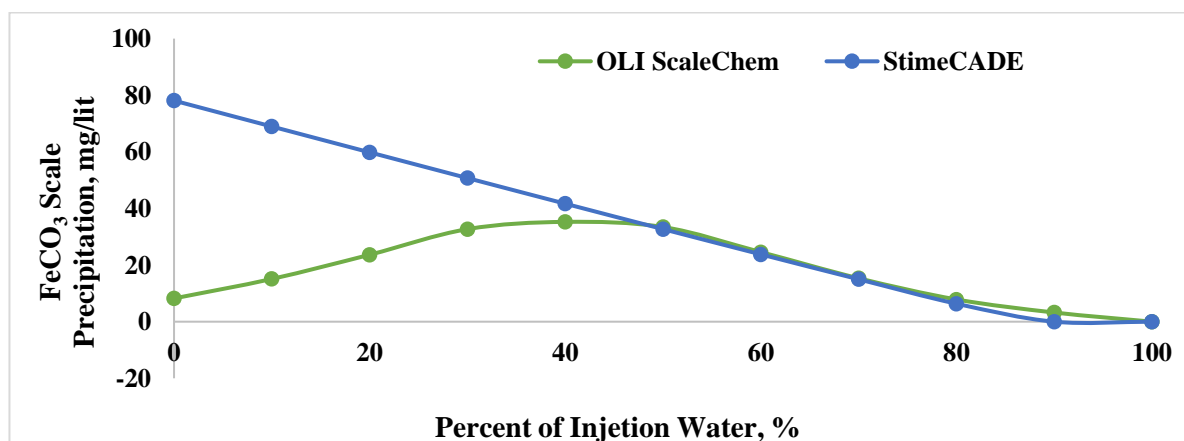


Figure 12

FeCO₃ scale precipitation versus the percentage of injection water at a temperature of 182 °F and a pressure of 4563 psia.

7. Scale prevention and mitigation

As mentioned, scale formation is typical in water injection systems such as flow lines, well column, near-wellbore, and production facilities. In the near-wellbore area, scale formation and deposition can cause permeability reduction and injectivity/productivity impairment. Several chemical and nonchemical methods have been proposed and performed in oilfields. The injection of scale inhibitors has been widely used to prevent scale formation in injection and production wells. Mechanical methods have been applied for some hard scales, and acid injection is another solution for acid-soluble scales such as calcium carbonate. Ultrasonic methods have also been proposed for scale removal and mitigation. Applying a suitable method depends on the reservoir and operational conditions and requires careful experimental and field performance analysis.

8. Conclusions

The following main conclusions can be drawn from the findings of this work:

- Laboratory tests and accurate modeling are necessary to predict scale formation in Sarvestan and Saadatabad oilfields injection wells.
- Temperature change has the primary effect on scale formation. At high temperatures, calcium carbonate deposition increases because the solubility of CaCO_3 declines with increasing temperature.
- The scale deposition of calcium carbonate and iron carbonate increases by pressure drop. Pressure drop raises CO_2 partial pressure and the scale deposition of calcium and iron carbonate.
- The incompatibility between formation water and desalting unit water forms CaCO_3 and FeCO_3 as the dominant scales in a disposal well.
- Frequent water sampling and analysis are recommended to check changes in water composition and estimate scaling risk.

Nomenclature

a_i	The activity of the species of reaction
K_{sp}	Solubility product, M^2
M	Molal concentration, mg/lit
P	Pressure, psi
Q	Activity product
SG	Specific gravity
ST	Scaling tendency
T	Temperature, °F
TDS	Total dissolved salts, mg/lit
γ_i	Activity coefficient for species of reaction

Conflict of interest statement

The corresponding author states that there is no conflict of interest on behalf of all authors.

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