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THE POSSIBILITY OF USING SEA WATER INJECTION INTO PETROLEUM RESERVOIRS AND REDUCING THEIR SCALE PRECIPITATION IN INJECTION AND PRODUCTION PIPELINES

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Abstract

In oil reservoirs, the pressure energy is declined ,due to the production of reservoir fluids. Waters from sea or water – wells are usually injected into the reservoirs to conserve this energy. Mixing the injected water with that existed in the reservoir results in scale deposits, which lead to plugging of the porous media around well-bore in injection wells.

Regarding the cost of drilling injection wells, we have to prevent or minimize the scale deposits in the porous media. This problem can be bridged by using scale inhibitor. Therefore, the main objectives of this study is to first evaluate the scale tendency in the porous media,resulting from mixing of two incompatible waters and second to evaluate the scale tendency after adding the proper scale inhibitor to the injection waters.

In this study, experimental work and **ScaleChem** software were used to evaluate the scaling tendency of the commingling of two incompatible waters for the Egyptian oil reservoirs existed in the Gulf of Suez area. The chemical analyses of the two incompatible waters (injection and formation waters) have been used, as input data to the computer simulator. The reservoirs characterized by a temperature range of 90-127ºC, and a salinity range of 100,000-230,000 ppm. The scaling results for the commingling of both injection and formation water is at the reservoir temperature and pressures were determined from the experimental work and software. Results showed that ,mixing of the injection water with (60%) and formation water with (40%) leads to deposits with considerable amounts of $CaCO_3$ and $BaSO_4$ scales in the absence of scale inhibitor. Adding scale inhibitors to the injection water reduces the porous media plugging by 21.325 to 29.2 %. The proper scale inhibitor for the studied reservoir was AII ,which has an efficiency of 67.09 and 78.012 % for the formation types A and B, respectively.

Keywords: *Scale inhibitor; Scale prediction; Scale deposition; Software simulator.*

1. Introduction

Scale is adherent forms of inorganic solids,that deposit on production equipment surfaces [1]. Due to the extensive use of water injection for oil displacement and pressure maintenance in oilfield, many reservoirs experience the problem of scale deposition ,when injection water starts to break through [2]. Formation of mineral scale deposits is undesirable processes, where water and water treatment are involved, such as cooling system, boilers, heat exchangers, filtration, mineral processing, oil and gas production, and geothermal systems [3]. Scale build-up can, in fact, seriously compromise the production efficiency of a reservoir to the point, where production has to be discontinued and the well cleaned. Scale deposition can occur anywhere in a production system, most commonly on the surface production equipment, well-bore surface and the near wellbore formation [4].

Oilfield scale has long been recognized ,as one of the major chemical problems in the production of oil and gas industry. The formation of mineral scale, as may result in greatly reduced well performance as rock pores. Tubulars and topside machinery become choked by a build up of insoluble inorganic precipitate [5]. Scale can develop in the formation pores near the wellbore–reducing the formation porosity and permeability. It can block flow by clogging perforations or formatting a thick lining in production tubing. It can also coat and damage downhole completion equipment, such as safety valves and gas-lift mandrels [6]. Scale can be deposited all along the water paths from injectors through the reservoir to surface equipment. Most of scales found in oilfield are formed by either the mixing of two incompatible brines or sudden changes in produced fluid conditions, such as pressure, temperature, or pH [7].

An oil field is a natural accumulation of hydrocarbon in the pores of underground rocks, which are called reservoir rocks, or simply reservoir. Hydrocarbons are recovered from the reservoir by means of wells drilled from the surface.

When an oil reservoir is connected to the surface by drilling, some of the oil may be spontaneously produced, because of the natural pressure that exists in the reservoir. The amount of oil produced by the energy of the reservoir itself, as well as by pumping of individual wells to assist the natural drive is known as primary oil recovery. At the end of the primary production period, the recovery factor is low, usually less than 25% of the original oil in place. For improving oil recovery, various techniques are used to maintain reservoir pressure and to sweep the oil towards the production wells. Amongst these techniques are the water injection, inert gas injection, re-injection of produced gas and methods of enhanced oil recovery. One of the most common techniques is water injection. Injection wells are used to inject fresh water, seawater or formation water into oil reservoirs, in order to maintain reservoir pressure or sweep reservoir oil by water. Pressure maintaining operations are generally referred to as secondary recovery or water flooding [2]. Water that exists naturally within the pores of rock, called formation water, usually contains significant amounts of divalent cations, such as calcium (Ca^{2+}), magnesium (Mg^{2+}), barium (Ba^{2+}), and strontium(Sr^{2+}), These cations can react with anions, such as sulfate(SO_4^{2-}) and carbonate (CO_3^{2-}) that occur in the injected brine water to produce insoluble scale. The development of a scale is amultistage process, of which adhesion of the fouling agent to surfaces is an essential step. Mineral scale deposition causes serious damage in utilization systems and reduces flow areas. Well production and injection rates and capacities thus drop, with consequent economical loss. The cross-section decrease caused by solid deposition onto the inner wall of a pipe. In some cases, the choke of the flow line is so large that, the well needs to be closed [8]. Scaling can also cause safety problems caused by blockage and failure of valves [9].

2. Materials and mehods

2.1. Materials

The materials used were formation and injection waters, core samples and commercial inhibitors. Two types of waters were used in this study: formation and injection waters from four different producing oil fields (Scimitar, Agiba, WestBakr H12 and WestBakr H13) Gulf of Suez) (Red sea).

Two types of commercial inhibitors indicated by: AII and SII were obtained from the local market use for this study. Sand stone core samples were used for scale tendency and scale inhibitors evaluation. The physical properties of the core samples such as permeability and porosity were experimentally determined .

2.2. Methods

The methods used in this study are divided into two parts: theoretical and experimental work. The quantitative calculations of scaling tendency (ST) were performed, using ScaleChem, which is a specific software designed to theoretically estimate the scale formation conditions and scale quantities, that may result from mixing two incompatible waters at one or more specified temperature and pressure, and any specified ratio of mixing to simulate the reservoir conditions. The input data to the software were the results of two mixing waters. Reservoir pressure and temperature ,as well as mixing ratios were also added to complete the run.

In evaluating the sensitivity of the runs, it can be concluded for the most favorable conditions for harming scale, that should be avoided. However, the theoretical analysis should be just a stage towards complete laboratory testing of the scale phenomenon. Jar tests different scale inhibitors consider there concentration should follow the theoretical evaluation.

3. Core flooding

3.1. Plugging stage

Plugging program was designed to maximize the number of plugs being cut per each preserved sample. Careful cutting process has resulted in plugging about 4 plugs. The core segments preserved in wooden boxes were received from the subject wells to use in this study. These cores, drilled with a water-based drilling fluid, were sampled at selective intervals, using a diamond core drill with simulated formation water, as a bit coolant and lubricant. The 1.5-inch diameter cylindrical core plugs obtained were trimmed with a diamond core saw to a uniform right cylinder. The samples were numbered for identification.

3.2. Sample cleaning

Hydrocarbons were extracted from the plug samples in a cool solvent reflux Soxhlet using toluene. Any salt present was leached from the samples methyl alcohol in a solvent reflux soxhlet extractor. The sample was considered to be clean of salts when the methanol in direct contact with plug was free from precipitate, when tested with a 10% silver nitrate solution, and clean of residual hydrocarbon, when the core plugs did not show any fluorescence, when viewed under ultraviolet light. The samples were dried in a humidity oven, which was maintained at 45 percent relative humidity and 60°C (140F) to minimize vaporization of clay-bound water. The samples were weighed daily until a constant weight was attained.

3.3. Steady-state air permeability

The clean, dry samples were initially callipered to determine the length and diameter. The core plugs were loaded individually into a Hassler-type core holder, with the circumference sealed to prevent bypass, using an overburden pressure of 400 psi. Dry air was injected through the samples at a constant pressure. The pressure differential across the length of each sample was measured, and the flow rate of the air permeability was determined.

3.4. Helium porosity

The clean, dry samples were initially callipered to determine the length and diameter, and then weighed to determine the dry weight. The bulk volume of each sample was determined using a mercury pycnometer. Each sample was then placed in a sealed sample chamber (matrix cup); using steel disks to minimize void space. The reference cell containing a known volume was pressurized with helium to 100 psi. The helium in the reference cell was then allowed to expand into the sample chamber containing the sample to define the porosity.

3.5. Sample saturation

The samples selected for this study. Involve two samples A and C possessed higher formation quality, while samples B and D had low formation quality. They were initially loaded into a saturation cell and evacuated for a minimum of 16 hours. The cell was then filled with simulated formation brine containing approximately 5% salinity. The pressure was increased to 2000 psi and maintained for a minimum of two hours. The brine-saturated samples were removed from the cell and weighed. The gravimetric saturated pore volume was calculated and compared to the gas expansion pore volume to verify complete saturation.

3.6. Formation reduction measurements

The saturated core plugs were placed in core holder under confining pressure of 2500 psi and the formation brine was displaced with oil obtained from the subject well. The permeability to formation brine was determined at a low flow rate (2cc/min).

The injection water (free of scale inhibitor) flowed through the plug till a 14-pore volume was reached. The liquid permeability at each volume step is recorded and consequently permeability reduction was calculated. A certain weight of scale inhibitor (AII or SII) was dissolved in 16 pore volumes of the injection water to get the desired concentration of scale inhibitor. Following this, the 16-pore volume of injection of water was flown through the plug. The recovery in permeability was determined at each step. The procedure was followed for plugs A and B using scale inhibitor AII, and plugs C and D using scale inhibitor SII.

Table 1. Comparison between four plugs

No.	Plug ID	Liquid permeability, mD	Air permeability, mD	Porosity pore volume, %
1	A	287	453	15.8
2	B	34	65	10.5
3	C	269	361	14
4	D	29	52	8.77

4. Results and discussion

4.1. Analysis of brine water

The chemical analysis of oilfield water has an important role in exploration and production of petroleum, for treating the corrosion problems in primary and secondary recovery, treating the scaling problems in water flooding operation, control the content of some ions to prevent its reaction with other ions, and evaluation of its compatibility with other injection water [10].

Four samples of formation and injection waters associated with crude oils produced from individual wells at oil-fields on the Gulf of Suez were kindly provided. The water samples were filtered using ashless filter papers (Whatman No. 42) before they were subjected to the analysis.

4.2. Probability of scales formed from results of water analysis

Using software out put for all fields under study, expected types of the scales were seen to be identical with that in the estimate from water analysis results. From the above physicochemical properties, it was found that, there is an incompatibility between different waters in the same field and in the different fields, the predominant cations and anions in Scimitar field were Ca^{2+}, Ba^{2+}, SO_4^{2-}, HCO_3^- for both formation and injection water, and therefore, the probability of scale formed were $BaSO_4$ and $CaCO_3$. By the same manner, its found that in the Agiba field the ferrous ion (Fe^{2+}) appeared in addition to the presence of Ca^{2+},SO_4^{2-}, HCO_3^- ions in the analysis of both waters. So the probability of formation $FeCO^3$ scale was expected beside the formation of $CaCO_3$ As well as both of West Bakr (H12, K) and (H13, K) fields have an ability to form of $SrSO_4$ due to presence of Sr^{2+} ion in the water analysis beside the previous scales.

Table 2. Summary of probable scale formed in the oil fields underninvestigation

Fields	Scale prediction after mixing	Common cations & anions in formation	Common cations & anions in injection
Scimitar	$BaSO_4$ (Barite) and $CaCO_3$ (Calcite)	Ca^{2+}, Ba^{2+}, SO_4^{2-} and HCO_3^-	Ca^{2+}, Ba^{2+}, SO_4^{2-} and HCO_3^-
Agiba	$FeCO_3$ (Siderite) and $CaCO_3$ (Calcite)	Fe^{2+}, Ca^2, $SO_4^{2-}$and HCO_3^-	Fe^{2+}, Ca^2, $SO_4^{2-}$and HCO_3^-
West Bakr (H12 , K)	$CaCO_3$ (Calcite), $SrSO_4$ (Celesite) and $BaSo_4$ (Barite)	Ca^{2+}, Sr^{2+}, Ba^{2+}, SO_4^{2-} and HCO_3^-	Ca^{2+}, Sr^{2+}, Ba^{2+}, SO_4^{2-} and HCO_3^-
West Bakr (H13 , K)	$CaCO_3$ (Calcite), $SrSO_4$ (Celesite) and $BaSO_4$ (Barite)	Ca^{2+}, Sr^{2+}, Ba^{2+}, So_4^{2-} and HCO_3^-	Ca^{2+}, Sr^{2+}, Ba^{2+}, So_4^{2-} and HCO_3^-

4.3. Theoretical prediction of scales formed at different conditions

The scale tendency for mixed brines used in the current study has been predicted using a ScaleChem (V2.2) software at ambient and reservoir conditions. The software predicts the relationship between the percentage of formation to injection water and the corresponding predicted parameters are represented by scale tendency (ST), scale index (SI) and maximum scale mass.

4.3.1 Scale tendency

The scale tendency is defined as the ratio of the activity product (Q) for equilibrium to the solubility product (Ksp) for the same equilibrium. i.e., ST=Q/Ksp. When the ratio of Q/Ksp is greater than1.0, the solid is said to have a thermodynamic driving force to form. When the ratio is less than 1.0, the solid does not have the driving force to form. When the ratio equals 1.0, the solid is considered to be at saturation. The solubility product, usually represented as Ksp, is the thermodynamic equilibrium constant, a function of temperature and pressure. ScaleChem accurately calculates the equilibrium constant, Ksp, as a function of temperature and pressure, for all solids. The scale tendency was studied under both ambient and reservoir conditions .

4.3.2. The scale index (SI)

The scale index is the logarithmic volume of the scaling tendency i.e., $SI=\log_{10}(ST)$. The positive SI (SI>0) can indicate that, the solution (brine) is supersaturated, i.e., from the view of thermodynamics, the scaling ions will have a tendency to form. On the contrary, the negative SI (SI<0) indicates that the solution (brine) is unsaturated and there is no potential for the scale to form [11]. The scale index was studied under both ambient and reservoir conditions

4.3.3. The maximum scale masses(g)

The maximum amount of scale identified by the output data from the ScaleChem (V2.2) program was symbolized by mg/L or lbs/bbl). The maximum scale masses was studied under both ambient and reservoir conditions for four fields cases.

5. Experimental work

Experimental jar tests were conducted to confirm the results of the simulator. The results of Scimitar field indicated that the maximum scale formed is 473.654 mg/L and it was attained at formation: injection waters of 60:40. The results of maximum scale amount of Scimitar field determined using the jar test and its corresponding maximum scale amount from ScaleChem (V 2.2) These results conformed to both the tools used to calculate and understanding the meticulous thermokinetic process, that causes the scale .

It was found that the ratios of 60:40 of formation water lead to scale deposition, and its ratio can be considered as the worst ratio, which must be take in consideration, when re salts the scale problem.

The worst ratio, that cause sever scale deposition in Agiba field was 40% of formation water, and the maximum scale mass was 384.6 mg/L. Also, this ratio resulted from the experimental measurement is in agreement with the trend obtained from the ScaleChem (V 2.2) software, but with more severity .

It was found that, the worst ratio that cause severe scale deposition in West Bakr (H12, K) and (H13, K) fields were 40:60 and 80:20 of formation water, respectively. Also, such ratios are in agreement with both the experimental measurements and theoretical predication trend.

It can be conclude that, the experimental jar test and the scale predication software is in agreement with each other in the trend (i.e., maximum scale ratios), but may differ in the maximum amount of scale produced from each output. All the above cases, except Scimitar show that,the amount of scale produced from experimental work was higher than that predicted by the software simulation.

Table 3. Expected scale scenario before and after inhibitor injection for all fields at reservoir conditions

Field	Total maximum mass (ϒ)				Change in the standard range	Change in expected scenario
	Before inhibitor injection		After inhibitor injection			
	Theoretical	Experimental	AII	SII		
Scimitar	598.48	473.654	182.8	171.4	From 300-700 to 100-500	From severe to moderate problems
Agiba	46.57	384.6	82.4	92.6	From 300-700 to < 100	From moderate to few problem
West Bakr H12	35.4	346.8	113.6	100.8	From 100-500 to >100	Moderate problem to few problems
West Bakr H 13	61.68	317.8	182.8	96.8	From 100-500 to < 100	Moderate problems to few problems

5.1. Application to core flooding

Applications of scale tendency evaluation were examined and the results given in the Figures (1,2,3,4 & 5). The results show severe plugging ranged from 37.4 to 40.624 in the porous media. Adding scale inhibitors to injection waters restored 29.2/37.4, 25.683/38.278, 25.353/40.624, and 21.325/39.697 for plugs A, B, C and D, respectively.

Ensure that, the selection of scale inhibitor SII for minimize the scale deposits in the studied reservoirs.

Table 4. Performance of scale inhibitors AII & SII

Core ID	% of plugging in porous media	% of restoring in porous media	Scale inhibitor efficiency, %
A	37.4000	29.200	78.012
B	38.2780	25.683	67.090
C	40.6240	25.353	62.409
D	39.6970	21.325	53.720

Inhibitor AII was considered as the most economically feasible scale inhibitor and its optimum concentration was determined in each case individually. Generally, the present study shows very good agreement between the theoretical and experimental evaluations. Accordingly, it was very useful to apply the software calculation to predict the scale potential, as a quick and reliable evaluation.

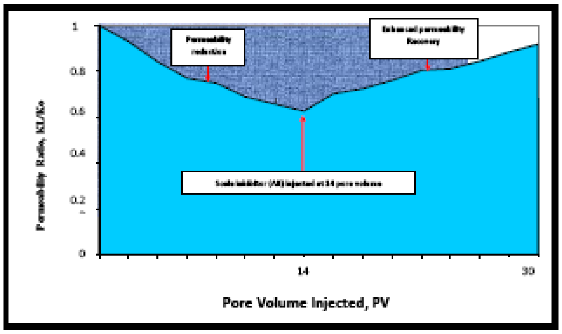

Figure 1. Effect of scale inhibitor performance on permeability recovery A, scale inhibitor ID= AII

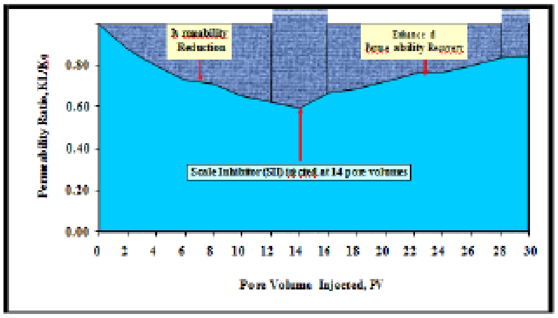

Figure 2. Effect of scale inhibitor performance on permeability recovery. C, scale inhibitor ID= SII

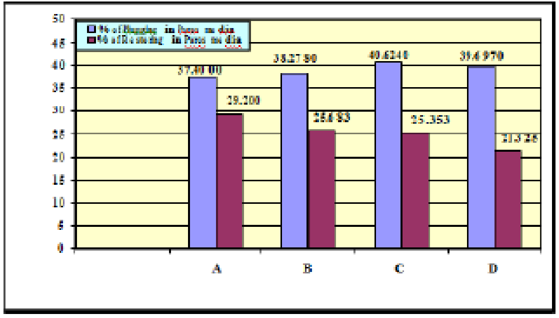

Figure 3. Plugging due to scale deposits and restoring due to using scale inhibitor

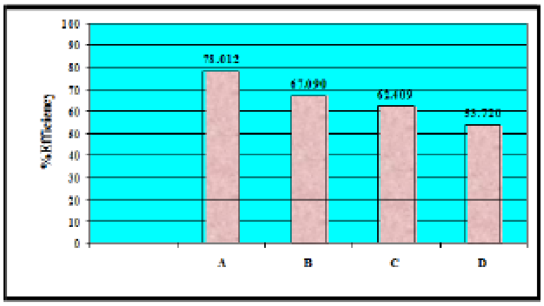

Figure 4. Scale inhibitor efficiencies

6. Conclusion and recommendation

Oilfield scale has long been recognized as one of the major chemical problems in the production of oil and gas industry. The formation of mineral scale may result in effectively reduced well performance as rock pores.

Most of scales found in oilfield are formed either by the mixing of two incompatible brines or sudden changes in the produced fluid conditions, such as pressure, temperature, or pH. The most commonly used approach to scale control in produced water injection operations is to inject chemical scale inhibitors.

Scale inhibitors can reduce the tendency for crystallization or completely prevent scale formation and growth by disrupting the thermodynamic stability of growing nuclei, causing dissolution of nucleated scale and/or interfering with the crystal growth process, resulting in blockage of the growing.

Two types of waters were used in this study: formation and injection waters from four different producing oil fields (Scimitar, Agiba, West Bakr H12 and West Bakr H13). First, theoretical studies were applied on the four fields to predict the tendency, for scale formation, scale index and maximum scale mass, using the computer software (ScaleChem). The results showed that all fields under investigation can form scale after water injection but with different values and with various types of scales (barite ($BaSO_4$), calcite($CaCO_3$), gypsum ($CaSO_4.2H_2O$), celesite ($SrSO_4$) and siderite ($FeCO_3$), according to the compositions of the two waters. Consequently, Scimitar will be the worst case .

The effect of pressure and temperature on the scale deposits investigated. The ScaleChem Program was used to predict the effect of these factors on the formation of mineral scales. This option introduces the effect of different scenarios (combination) of pressure and temperature ranging from reservoir conditions to ambient ones. From the out put scale scenarios results, prediction of the scale growth and the affects in change in pressure and temperature.

Jar tests were applied on the four fields at the reservoir conditions. The results obtained from these tests confirmed the expected scenario, that come from the soft ware and that from water analysis. There was a similarity between the practical work and the theoretical work, with a limited difference in the numerical values.

Jar tests gave the same trend of the worst ratios. The worst ratio for Scimitar, Agiba and West Bakr H12-K fields was at the ratio of 60:40 of formation water to injection water. On the other hand, for West Bakr (H13-K) field, the worst ratio was 80:20 of the formation water to injection water. All the above cases, except Scimitar show that the amount of scale produced from experimental work was higher than that predicted by the software simulation due to additional chemical properties. Different concentrations (25, 50, 75, 100 and 150 ppm) of the two individual commercial scale inhibitors designated AII and SII were evaluated to the worst mixing ratio of formation to injection water at reservoir conditions.

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