Simulation and Experimental Studies of Mineral Scale Formation Effects on Performance of Sirri-C Oil Field under Water Injection

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ABSTRACT: *Water injection is an enhanced oil recovery method which is applied for number of reservoirs especially in the offshore fields around the world. Sea-water injection process is usually associated with important concerns affecting the efficiency, safety, and economy of the operation like formation damage, mineral scaling, early breakthrough and corrosion. Incompatibility between injected and formation waters may result in inorganic scale precipitation in the reservoir and then reduction of oil production rate (productivity loss) and water injection rate (injectivity loss). A comprehensive study supported by reliable modeling and experimental investigation will therefore, significantly improve the success of the operation. In this paper, mineral scale deposition phenomenon in Sirri-C offshore carbonate oil field under water injection is studied and its influence on reservoir performance and production rate is investigated. For this purpose, a series of experimental work has been conducted to study the compatibility of sea and formation waters. Amount and type of scales formed as the result of mixing different portions of these waters have been applied and incorporated with simulation studies. STARS simulator (from CMG 2005) that is capable of evaluating the effect of scale formation on reservoir performance allowing for alteration of permeability and the flow path has been used in simulation study. One of the major contributions of this work is to incorporate the equilibrium conditions, reaction rates and solubility parameters for various scale types in reservoir simulation, so the results can be more realistic. The simulation results show that in Sirri-C oil field, scale formation undermines the productivity index and has a major impact on reservoir performance.*

KEY WORDS: *Simulation, Water injection, Formation damage, Mineral scale deposition.*

INTRODUCTION

Water injection is a common IOR method, usually applied in offshore oil fields for the purpose of pressure maintenance and enhanced oil recovery. During secondary and tertiary recovery by this method, reductions of permeability have been observed in many reservoirs. Several sources are recognized as possibly contributing

to this problem such as mineral scale deposition, solid invasion, clay swelling and rock-fluid incompatibility.

One of the most important and hazardous kinds of these phenomena is mineral scale deposition due to the incompatibility between injected and formation waters and changes in temperature, pressure, gas dissolution and pH. In the other hand, this is a process of deposition of scales from aqueous solutions of minerals, referred to brines, when they become supersaturated as the result of changes in the state of their thermodynamic and chemical equilibria [1].

In water injection process, mineral scale deposition generally occurs when foreign fluids (usually brines) are contacted with another one. Fluids rich in divalent ions such as calcium, magnesium, barium and strontium often tend to be the worst offenders in this area, even though their high divalent ion concentration may make them desirable for inhibiting formation damage from a clay swelling or deflocculation viewpoint.

Mineral scale deposition causes serious damages in utilization systems and reduces flow areas. Well production and injection rates and capacities drop with consequent economical loss. For example, BP loses around 4 million bbls per year in the North Sea [2]. It can also plug production lines and equipment and impair fluid flow. The consequence could be production-equipment failure, emergency shutdown, increased maintenance cost, and overall decrease in production efficiency. The failure of these equipments could result in safety hazards [3-5].

A field example is Sirri-C offshore oil field in the southern Persian Gulf. This field produces from Mishrif formation that is common between Iran and United Arab Emirates. Water injection into the Sirri-C field was started at 1984 with 9100 bbl/day in order to maintain the pressure and to increase the oil recovery. However, the injectivity decreased rapidly until it was stopped at 1990 when the water injection rate had dropped to only 2200 bbl/d (Fig. 1) [6-10].

The aim of this paper is to present the results of experimental and simulation studies on the mechanisms of formation damage caused by mineral scale deposition in formation of Sirri-C oil field by using proper experimental and simulation works. Detailed compatibility studies completed with calculation of scaling coefficients, should be undertaken for any large-scale water injection scheme and any field simulation studies. So, in order to perform
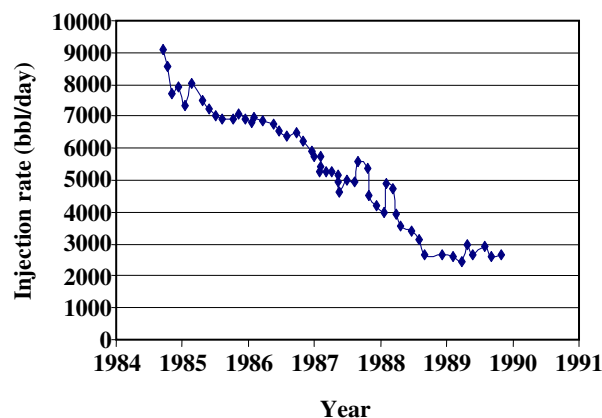

Fig. 1: Water Injection Rate History in Iranian Sirri-C Oil Field **[6-10].**

the simulation study on mineral scale deposition which is the main object of this paper, firstly, formation water and injected water (Persian Gulf sea water) analyses are required, and then the type of deposited scales should be determined from analyses of deposited scales during compatibility experiment or using practical correlations. Finally, the above mentioned conducted experimental studies result in the required data for modeling of scale deposition.

EXPERIMENTAL STUDIES OF MINERAL SCALE DEPOSITION

Formation and injected waters were analyzed in laboratory of IOR Research Institute and the results are given in Table 1. It can be concluded from this table that the main deposited scales from mixing of injected and formation waters would be calcium carbonate, calcium sulphate and strontium sulphate [6].

The atmospheric setup shown in Fig. 2 was designed and constructed for compatibility experiments. Mixtures of injected and formation waters were put in a two layer glass cell and heated by a heat bath liquid circulating in outer layer of the cell. Down mounted heater supplies the heat from downward and down mounted mixer mixes the solution to homogenize it. A thermometer mounted above the cell shows the solution temperature. This cell has the capability of adding the solution or material to or removing from it. Also, pH and turbidity data are gathered from pH Meter and Turbidity Meter sets which are connected to the setup. This setup was commissioned for both of unique and binary salts and reported separately [6].

Table 1: Concentration of Different Ions in the Injected and Formation Waters.

Ions	Formation Water (mg/L) – pH=6.8	Injected Water (mg/L) – pH=7.7
Cl^-	73942	23000
Sr^{2+}	547	3.4
SO_4^{2-}	635	3350
Ca^{2+}	3032	267
HCO^{3-}	579	166
Na^+	42215	11750
K^+	1986	0
Mg^{2+}	759	2996
Ba^{2+}	0	0.09
Fe^{2+}	17	0.42
TDS	131472	40270
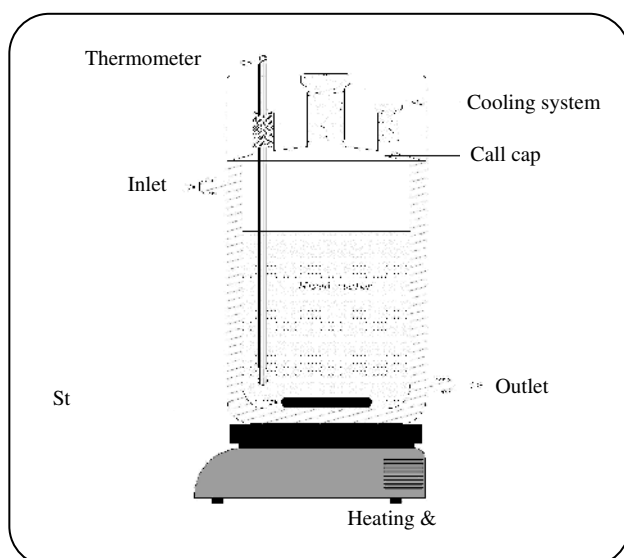
Fig. 2: The Atmospheric Compatibility Test Set-up.

Injected and formation waters were filtered separately using 0.45 micron filter. Different mixtures of these waters were agitated for sufficient time in ambient and reservoir temperatures (78.8 ˚F was selected for ambient and 212 ˚F for reservoir conditions) using the above atmospheric compatibility test set-up. The produced water mixtures were filtered by 0.45 micron filter for the purpose of weighting the scales and then these scales were analyzed in order to determine their types and compositions. Fig. 3 demonstrates the weight of scales

resulted from mixtures of the injected and formation waters at different ratios of waters.

As shown in this figure, the potential of scale deposition decreases as the injected water ratio increases. It also shows that the scale deposition increases with temperature as expected. The precipitated scales were analyzed by XRD method showing that they are composed of mainly calcium carbonate. At the ambient temperature, a considerable amount of Halite was also observed. Fig. 4 shows the XRD results for a scale sample resulted from 90% formation water and 10% injected water at the ambient temperature for instance.

Furthermore, Scaling Index (SI) study method was applied to examine the possibility for deposition of the mentioned salts in the wellhead and reservoir conditions for entire range of their mixing ratios. The conditional constants required to solve the SI equations for the salts of interest were gathered from literature data. These equations are function of temperature, pressure and ionic strength. When calculated SI=0, the solution is at equilibrium with the solid scale; as SI<0 is an undersaturated or nonscaling condition and SI>0 is scaling condition for the solution with respect to the scale in question. In this study, *Moghadasi et al.* procedure was used for SI calculations [9]. Fig. 5 shows graph of calculated SI values for calcium carbonate, calcium sulphate and strontium sulphate vs. mixing ratios of injected water in temperature of 212 ˚F and pressure of 4000 psia as typical reservoir condition. It can be seen that SI values for calcium carbonate and strontium sulphate are above zero and it means that these two salts can precipitate in the reservoir and damage it. While SI values for calcium sulphate confirm that this salt will not deposit for any mixture of the injected and formation waters at reservoir conditions. This figure also demonstrate that as the fraction of injected water increases, the calcium carbonate deposition decreases while for strontium sulphate, maximum deposition occurs at mixing ratio of injected water of 40%. It can be concluded that both of calcium carbonate and strontium sulphate have tendency of deposition based on theoretical analysis, while in experimental studies only calcium carbonate deposition was observed. Finally, regarding to above studies, the worst case was considered for simulation studies and it was assumed that both calcium carbonate and strontium sulphate can deposit at the reservoir
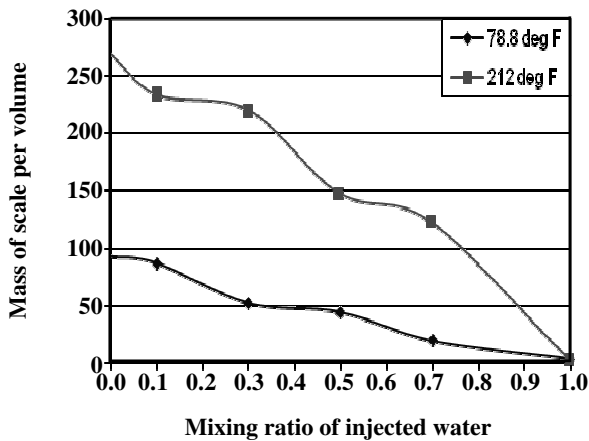
Fig. 3: Prediction of Scale in the Case of the Injected and Formation Waters Mixing at Atmospheric Pressure.
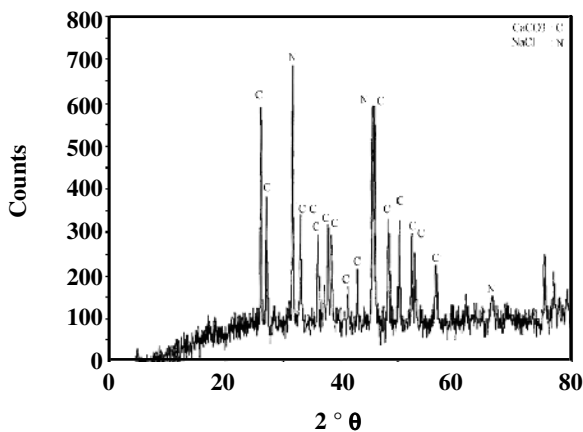

Fig. 4: XRD Analysis for a Scale Sample Resulted from 10% Injected Water and 90% Formation Water at the Ambient Temperature.
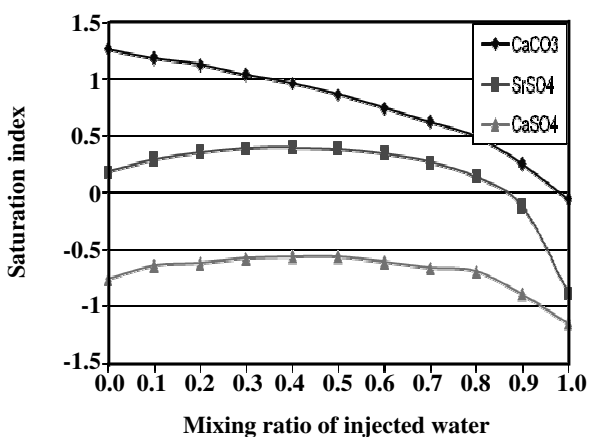

Fig. 5: SI Values for Various Scales in Reservoir Conditions (T=212 oF and P= 4000 psia).

condition and so these two scales, their components and relevant properties were selected as the input of simulator.

SIMULATION STUDIES OF MINERAL SCALE DEPOSITION

For studying the effect of mineral scale deposition on reservoir performance, an accurate reservoir simulator is required. CMG-STARS 2005 simulator has a capability of evaluating the effect of scale deposition on reservoir performance allowing for alteration of permeability and the flow path. It has the required potential to model mineral scale deposition in the reservoir as the result of incompatibility between injected and formation waters, reduction of pressure near the production well and increasing the temperature of injected water near the injection well [11]. In this work, a new approach for modeling of scale deposition considering the equilibrium conditions and solubility parameters for various scale types in the reservoir has been applied. This study is going to simulate water injection process considering the effect of calcium carbonate and strontium sulfate deposition on behavior of a synthetic model of Sirri-C oil field.

Building the Base Model

In this simulation study, available data from Sirri-C oil field have been used to create a simulation model [12]. Necessary validations were done on the above synthetic model. The procedure of building model is similar to the common synthetic models except that scale deposition model should be activated by defining the scale types and relevant parameters.
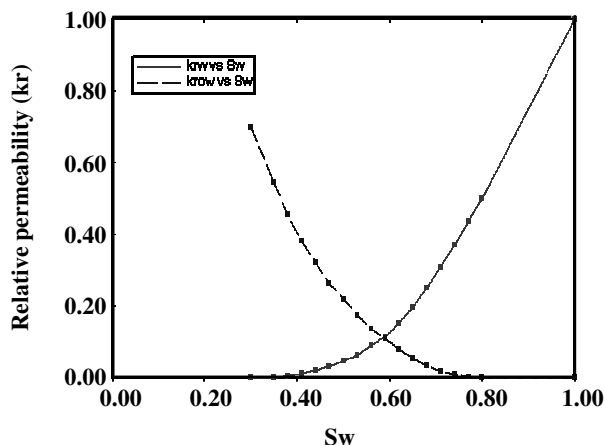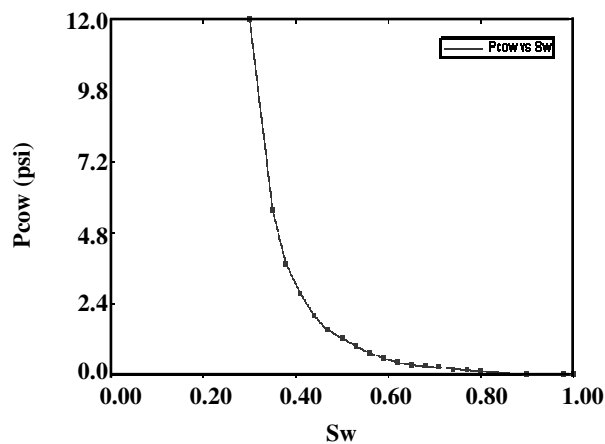
Reservoir Rock Properties

The basic reservoir rock properties of Sirri-C oil field, required for building simulation model are given in Table 2. The typical relative permeability and capillary pressure curves used for this simulation are also shown in Figs. 6 and 7 [12].

Reservoir Fluid Model

In simulation of scale deposition, a fluid model similar to common black oil model is used. Also thermal calculations, equilibrium definition and definition of reactions for precipitation of strontium sulphate and calcium carbonate required to study precipitation phenomenon are included in the model.

12

Table 2: Average Reservoir Rock Properties of Sirri-C Oil Field [12].

Properties	Value
Horizontal Permeability (md)	10
Vertical Permeability (md)	1
Porosity (fraction)	0.23
Rock Compressibility (psi^{-1})	2.74×10^{-5}
Rock Thermal Expansion Coefficient (F^{-1})	4.36×10^{-9}
Rock Heat Capacity (Btu/ ft^3 °F)	35
Rock Thermal Heat Conduction (Btu/ft °F)	24
Connate Water Saturation (fraction)	0.3
Residual Oil Saturation (fraction)	0.2

Fig. 6: Relative Permeability Curves for Sirri-C Oil Field [12].

Fig. 7: Capillary Pressure Curve of Sirri-C Oil Filed [12].

Properties of reservoir fluids are given in Table 3. Also the required properties of scales (strontium sulfate and calcium carbonate) are given in Table 4.

The main innovation of this work is some changes in procedure of defining deposition models that were used in previous studies [13].

In this study, except defining the deposition reactions and their reaction rates, solubility products and equilibrium conditions were incorporated into simulator and so the results of this study are more reasonable and can be used for both deep of the reservoirs and around the wells.

Strontium Sulfate Precipitation

Precipitation reaction of Strontium Sulphate is as follow:
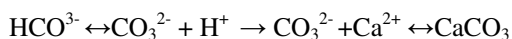
$$Sr^{2+} + SO_4^{2-} \leftrightarrow SrSO_4$$
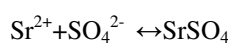
After defining this reaction in the simulator and giving the reaction rates and the other required parameters, the equilibrium K values should be defined for reaction of strontium sulphate deposition. In CMG-STARS, the equilibrium K values of the reaction can be related to Ksp by Eq. (1).

$$K_{Sr}^{2+} = 1/[Sr^{2+}]_{eq.} = [SO_4^{2-}]_{eq.}/Ksp \qquad (1)$$

Solubility product of strontium sulfate is a function of pressure, temperature and ionic strength. The injected water temperature is about 122 °F while formation water temperature is 212 °F. The ionic strength of injected and formation waters are 0.91 and 2.23 molar respectively. (Eq. (A.1)) So, the average ionic strength of 1.57 molar can be used for calculation of Ksp values for more simplicity. Fig. 8 shows the strontium sulfate Ksp as a function of pressure and temperature at ionic strength of 1.57 (Eq. (B.1)). It can be seen that strontium sulfate Ksp increases with increasing pressure and decreases with increasing temperature. By calculation of Ksp, an equilibrium K value table can be defined in the CMG-STARS for every sulphate concentration. These tables are function of sulphate concentration, pressure and temperature.

Calcium Carbonate Precipitation

Precipitation reaction of Calcium Carbonate is as follow:

$$HCO^{3-} \leftrightarrow CO_3^{2-} + H^+ \rightarrow CO_3^{2-} + Ca^{2+} \leftrightarrow CaCO_3$$

After defining these reactions in the simulator and giving the reaction rates and the other required parameters, the equilibrium K values should be defined for above

Table 3: Fluid Properties of Simulation Model [12].

Properties	Value
Oil Bubble Point Pressure (psia)	1435
Oil Viscosity (cp)	1
Oil Compressibility (psi^{-1})	1.0×10^{-5}
Oil Formation Volume Factor (bbl/STB)	1.208
Solution Gas Oil Ratio (scf/STB)	324
Oil Gravity(^{o}API)	31
Water Viscosity (cp)	0.32
Water Compressibility (psi^{-1})	2×10^{-6}
Water Density (lb/ft^3 @ 212ºF)	65.5
Water Thermal Heat Conduction (Btu/ft ºF)	8.6

Table 4: Solid Properties of Simulation Model

Properties	Value
SrSO$_4$ Density (lb/ft^3)	245
CaCO$_3$ Density (lb/ft^3)	165
SrSO$_4$ Heat Capacity (Btu/lbmole ºF)	0.14
CaCO$_3$ Heat Capacity (Btu/lbmole ºF)	0.217
SrSO$_4$ Thermal Heat Conduction (Btu/ft ºF)	24
CaCO$_3$ Thermal Heat Conduction (Btu/ft ºF)	24

two reactions using the same procedure for strontium sulphate. Like strontium sulphate, second equilibrium constant of carbonic acid, K_2 (CO_3^{2-} can be expressed as a function of HCO_3^- with this constant) and solubility product of calcium carbonate are functions of pressure, temperature and ionic strength (Eqs. (B.2) and (B.3)). Also average ionic strength of 1.57 is used for calculations of K_2 and Ksp in calcium carbonate. Fig. 9 shows the calcium carbonate Ksp as a function of pressure and temperature at ionic strength of 1.57 (Eq. (B.3)). It shows that the calcium carbonate precipitation increases as temperature increases or pressure decreases.

Mobility Changes

For considering the effect of scale deposition on permeability and finally reservoir performance, Eqs. (2) and (3) have been used [11].

$$R_{fw} = \prod_{j=1}^{n}[1 + RRSFT_j.Cs_j] \tag{2}$$

$$k_{ew} = k_a.k_{re}/R_{fw} \tag{3}$$

and the same for oil effective permeability.

Cs_j is concentration of solid number j and RRSFT is residual resistance factor determining for Strontium Sulphate and calcium carbonate experimentally. But because of lack of such experiments in this work, result of *Bedrikovetsky et al.* [14] following by some calculations were used.

Model Validation

For validation of precipitation model, the following tests have been done on a two-grid (each 900 feet in x direction, 1800 feet in y direction and 207 feet in z direction) one dimensional model in which the production and injection wells are closed. Initial reservoir pressure and temperature was 4000 psi and 212 °F and temperature of injected fluid was 122 °F.

In first case, the composition of formation water was used in model. Figs. 10 and 11 show the amount of calcium carbonate and strontium sulphate precipitation in the reservoir when the reservoir pressure decreases from 4000 psi to 2500 psi at constant temperature of 212 °F. The calculated precipitated solid concentration values (in pore volume scale) from the Ksp formula are 0.02024 lb/ft^3 and 0.009472 lb/ft^3 for calcium carbonate and strontium sulphate respectively which in comparison with Figs. 10 and 11, it can be seen that less than 4 percent errors exist in the calculations of simulation.

In second case, the composition of injected water was used in the model. Figs. 12 and 13 show the amount of calcium carbonate and strontium sulphate precipitation in the reservoir when the temperature increases from 122 °F to 212 °F at constant pressure of 4000 psi. The calculated deposited solid concentration values (in pore volume scale) from the Ksp formula are 0.0028 lb/ft^3 and 0.00 lb/ft^3 for calcium carbonate and strontium sulphate respectively which in comparison with Figs. 12 and 13, about three percent errors exist in the calculations of simulation.
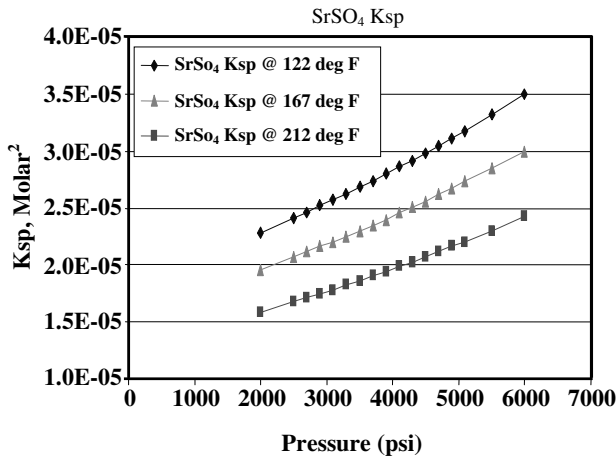
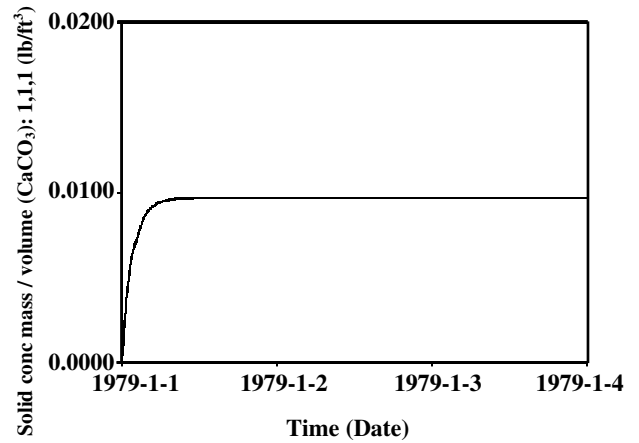*Fig. 8: Strontium Sulfate Ksp as Function of Pressure and Temperature.*

Fig. 11: Validation No. 1; Strontium Sulphate Precipitation at 212 ^{o}F.
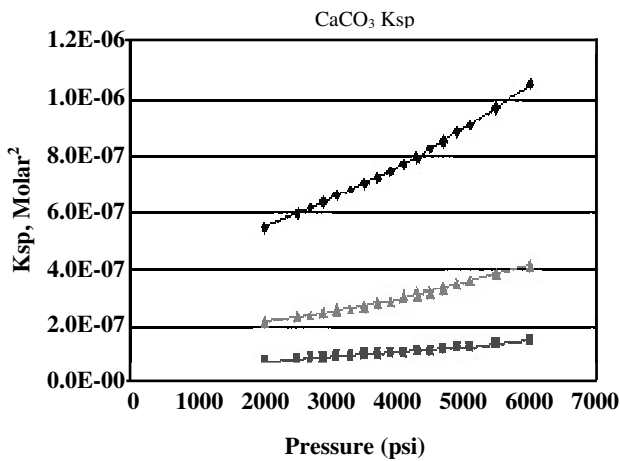

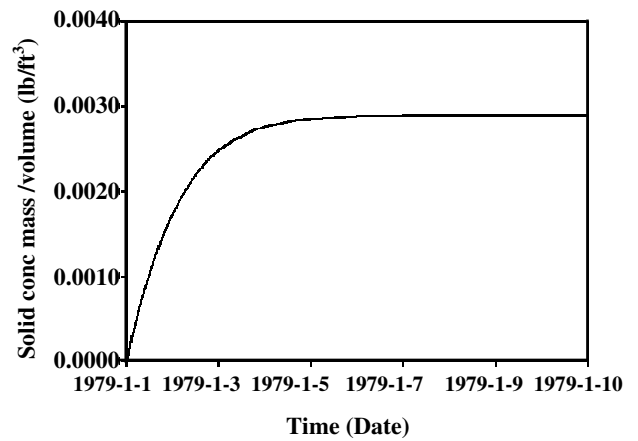*Fig. 9: Calcium Carbonate Ksp as Function of Pressure and Temperature.*

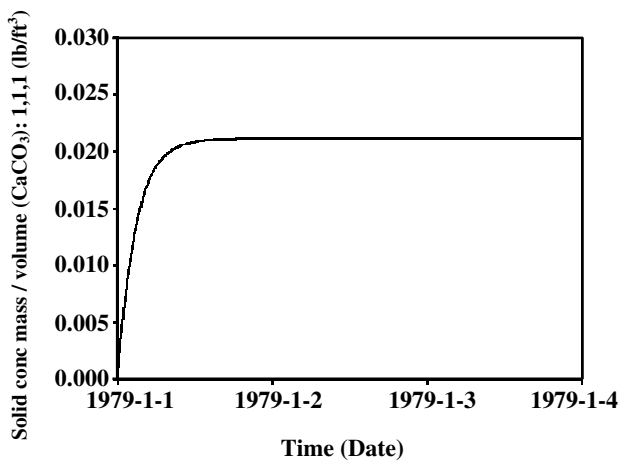*Fig. 12: Validation No. 2; Calcium Carbonate Precipitation at 4000 psi.*

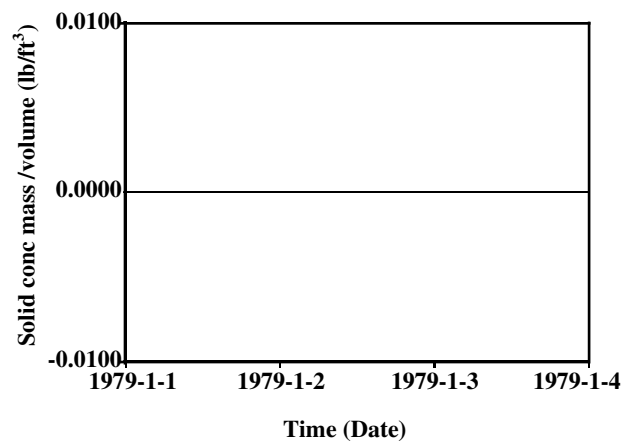*Fig. 10: Validation No. 1; Calcium Carbonate Precipitation at 212 ^{o}F.*

Fig. 13: Validation No. 2; Strontium Sulphate Precipitation at 4000 psi.

Initial Conditions

The required initial data for starting simulation runs are given in Table 5. The composition of injected and formation waters are given in Table 6 that are normalized values of compositions given in Table 1.

Chlorine was used as tracer because it does not react with any other ions in the reservoir as well as adsorb on the rock surface. Also, as the amount of chlorine is higher than other ions, the numerical error will not cause significant error in its amount value. It can be used to determine the percent of injected water in a water sample by Eq. (4).

$$\text{Percent of Injected Water} = \tag{4}$$

$$\frac{0.073942 - Cl_{Observed}}{0.050942} \times 100$$

Geological model

After applying the above data and assumptions in the synthetic model, various sensitivity analyses were done for selecting the optimum grid, time step sizes and number of sub-layers. Fig. 14 shows a 3D schematic of the final geological model (29×19×18=9918 grids). Depths of reservoir crest and water oil contact are 7713 ft and 9920 ft respectively. There are two semi analytical rectangular Carter-Tracy aquifer at the two ends of reservoir, each has 2000 ft long in x direction, permeability of 10 md, porosity of 0.23 and compressibility of 5.5×10^{-6} psi^{-1}.

Simulation of Scale Deposition under Different Scenarios

First of all, a natural depletion scenario is considered to have a sense about reservoir performance during natural depletion production. Then a water injection in the oil zone with injection bottomhole pressure of 4500 psi and production bottomhole pressure of 3000 psi has been considered as a base case. Installation of pump in production well, acidizing of production well and increasing bottomhole pressure of injection well which all have positive effects on oil recovery have been studied. Acidizing of injection well and reducing the number of perforations of production well have negative effects on the oil recovery. The same effect can be seen in water injection scenario in the aquifer zone that its recovery was less than water injection in the oil zone

Table 5: Initial Conditions of Simulation Model [12].

Properties	Value
Initial Oil in Place (STB)	27×10^6
Initial Gas in Place (scf)	8.7×10^9
Water Oil Contact Depth (ft)	7920
Initial Pressure (psi at 7874 ft)	4000
Initial Temperature (ºF)	212
Oil Gradient (psi/ft)	0.338
Average Thickness of Reservoir (ft)	207
Initial Water Saturation (fraction)	0.3
Initial Oil Saturation (fraction)	0.7

Table 6: Composition of Formation and Injected Waters.

Ions	Formation Water (mg/L)	Injected Water (mg/L)
Cl^-	73942	23000
Sr^{2+}	547	3.4
SO_4^{2-}	635	3350
Ca^{2+}	3032	267
HCO_3^-	579	166
Water	922265	9732136

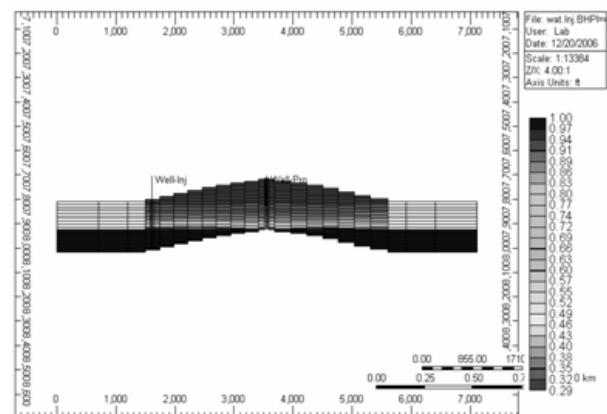*Fig. 9: Calcium Carbonate Ksp as Function of Pressure and Temperature.*
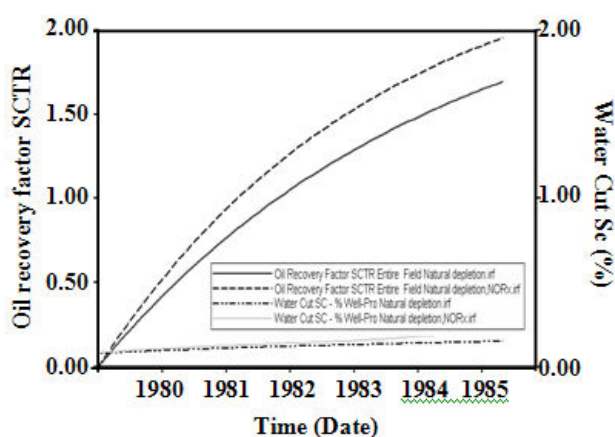
Fig. 15: Oil Recovery Factor and Water-Cut in Scenario No. 1.

Fig. 16: Solid precipitation profile between (5, 10, 2) and (17, 10, 8) Grid Blocks in Scenario No.1.

In the following sections, only the cases with increasing oil recovery will be explained.

Scenario No. 1: Natural Depletion (starting at 1979)

A production well was defined in the position of (17, 10, 2:10) with minimum bottomhole pressure of 3000 psi (regarding required wellhead pressure of 200 psia) and maximum liquid rate of 2000 STB/d. Minimum economical oil rate was set to 100 STB/d and maximum allowable water-cut was 80 percent.

Fig. 15 shows the oil recovery factor along with water-cut for natural depletion scenario with and without considering precipitation reactions (NORx is the case without considering the effect of solid deposition). It shows that the precipitated strontium sulphate and calcium carbonate will reduce the oil recovery, but does not have any significant effect on the water-cut. Fig. 16 shows solid precipitation profile between (5, 10, 2) and (17, 10, 8) grid blocks. It shows that some precipitation occurs in the reservoir because of pressure reduction. Also it can be seen that precipitation of calcium carbonate is more than strontium sulphate in the reservoir.

Scenario No. 2: Water Injection (starting at 1979)

An injection well was defined in the position of (5, 10, 2:10) with maximum injection pressure of 4500 psi, maximum injection rate of 2000 STB/d and injection temperature of 122 ºF. As there is no information about rock mechanics data in Sirri-C oil field, injection pressure of 4500 psi is applied without considering its effects

on reservoir rock. Fig. 17 demonstrate the oil recovery for both cases; with and without considering precipitation reactions. It illustrates that scale deposition will reduce the oil recovery considerably. Fig. 18 explains the reducing effect of scale deposition on the oil rate and Fig. 19 shows that water injection rate will reduce considerably as result of scale deposition.

Fig. 20 shows calcium carbonate deposition profile and Fig. 21 (small scale) and 22 (big scale) show strontium sulphate deposition profile between the injection and production wells (between (5, 10, 2) and (17, 10, 8) grid blocks). They demonstrate that the most scale deposition occurs near the production well because there is a lot of water which passes through the production wellbore and as the result of lower pressure around production well, the solubility of different ions will be lower which results in precipitation of calcium carbonate and strontium sulphate near the production well. Also there are some precipitation of calcium carbonate and strontium sulphate in the reservoir as the result of mixing and temperature rising. It should be noted that pressure decreases and temperature increases from injection well to the production well.

Figs. 23 and 24 show the amount of calcium carbonate and strontium sulphate deposition in different perforated grid blocks of production wellbore respectively. They illustrate that amount of scale deposition is higher in lower perforated grid blocks because more water passes through the lower perforated grid blocks.
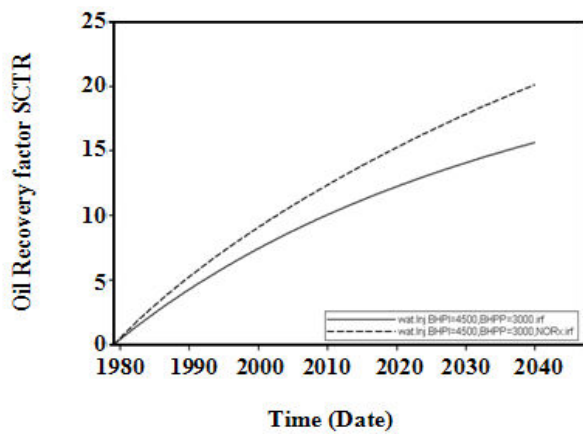
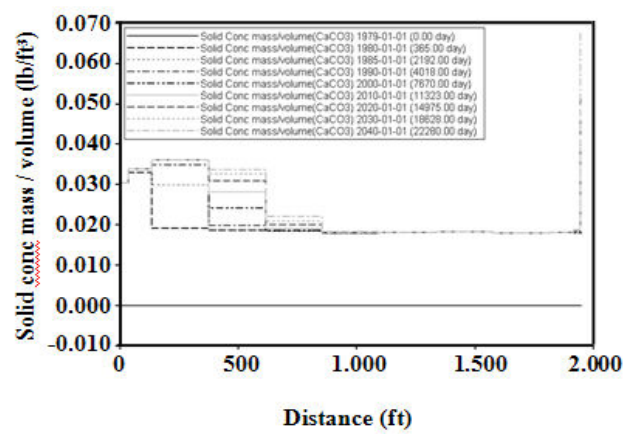*Fig. 17: Effect of Scale Deposition on Oil Recovery Factor in Scenario No. 2.*

Fig. 20: Profile of Calcium Carbonate Deposition in the Reservoir in Scenario No. 2.
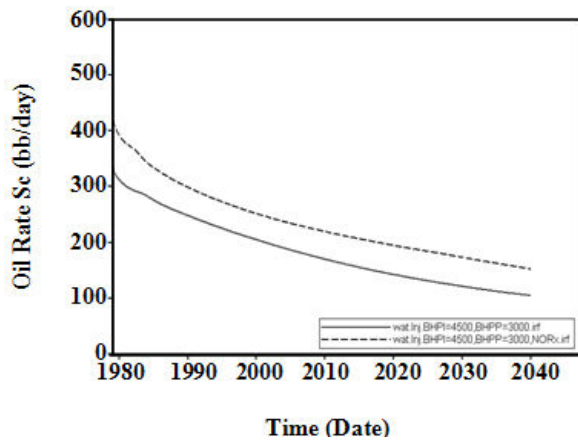

Fig. 18: Effect of Scale Deposition on Oil Rate in Scenario No. 2.
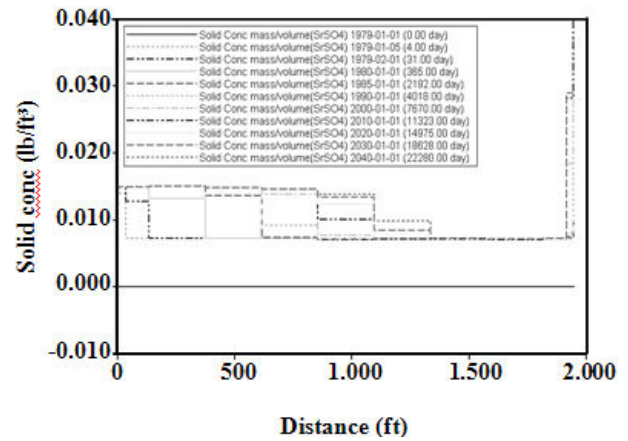

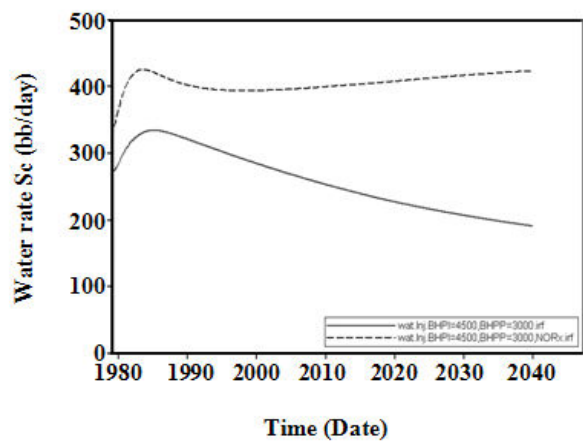*Fig. 21: Profile of Strontium Sulphate Deposition in the Reservoir in Scenario No. 2.*

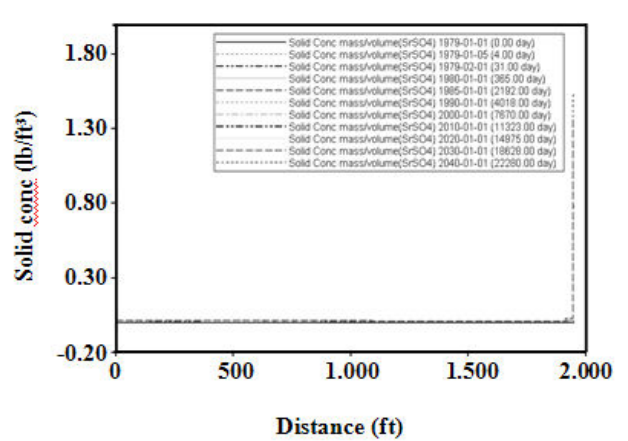*Fig. 19: Effect of Scale Deposition on Water Injection Rate in Scenario No. 2.*

Fig. 22: Profile of Strontium Sulphate Deposition in the Reservoir in Scenario No. 2.

Scenario No. 3: Water Injection with Using Pump in Production Well

In this scenario, pump will be installed in the production well in 2007 and water injection operation is continued. Modeling of pumps effects in the simulation have been done by decreasing bottomhole pressure of production well from 3000 to 2500 psi. Fig. 25 shows that oil recovery will be reduced considerably because of the scale deposition. Fig. 26 indicates oil rate reduction because of solid deposition during the production for this scenario. The role of installing the pump can be seen in Figs. 26 and 27 in date of 2007. Fig. 27 illustrates that there is one third decrease in water injection rate due to the scale deposition.

Scenario No. 4: Water Injection with Using Pump and Acidizing of Production Well

In this scenario, production well will be acidized and a pump with positive displacement pressure of 500 psi will be installed on the production well in 2007 and water injection operation is continued. Modeling of acidizing effects in the simulation have been done by decreasing the skin factor of the production well. As the skin factor of the production well in cases without acidizing is zero, skin factor of -2 that is common in any acidizing process is considered for production well in this case without considering the kind of acid. Fig. 28 shows the effect of scale deposition on the oil recovery, which decreases. The reducing effect of scale deposition on oil rate has been shown in Fig. 29. Fig. 30 indicates that water injection rate will reduce significantly as result of inorganic scale deposition in the reservoir. It can be seen that acidizing following by installing pump can have a considerable effect on oil recovery.

Scenario No. 5: Water Injection with Using Pump and Acidizing of Production Well and Increasing Injection Pressure

In this case production well will be acidized, a pump will be installed on the production well and injection well bottomhole pressure will be increased from 4500 to 5000 psi in 2007 without considering its effect on reservoir rock system. Figs. 31 through 33 show the effect of scale deposition on the oil recovery factor, oil production rate and water injection rate. Fig. 31 indicates that oil recovery will decrease due to the effect of scale deposition

significantly. Fig. 33 illustrates that due to the effect of scale deposition, water injection rate may decrease to one half of the value for the case without the effect of scale deposition.

RESULTS AND DISCUSSIONS

Fig. 34 indicates that using pump will increase oil recovery. It also describes that oil recovery will be increased by acidizing of the production well considerably during the time. In addition it shows that oil recovery will be increased by increasing the injection bottomhole pressure. Comparison of different scenario shows that the acidizing operation of production well has the greatest positive effect on the oil recovery.

Fig. 35 shows that using pump will increase oil rate. Also acidizing of production well and increasing injection well bottom hole pressure will increase oil rate considerably. It also illustrate that oil rate will be increased more due to the acidizing of production well. Fig. 36 shows the effect of using pump, acidizing of production well and increasing the injection bottom hole pressure on the water-cut indicating that the acidizing of production well has the greatest effect on increasing of producing water rate. Fig. 37 indicates that the water injection rate is increased by using pump in production well. Also acidizing of production well and increasing injection well bottomhole pressure will increase injection rate significantly.

Fig. 38 shows the amount of calcium carbonate deposited in perforated grid block (17, 10, 6) in production well for different scenarios. It shows that using pump will not have any great effect on the amount of deposited calcium carbonate. Acidizing of production well and also increasing the injection well bottomhole pressure will increase the amount of calcium carbonate deposited around the production wellbore significantly. Comparison of different scenarios shows that increasing of calcium carbonate deposition due to acidizing of production well is more than the other scenarios because producing water rate increases more for this scenario. Fig. 39 shows the effect of different scenario on the amount of deposited Strontium Sulphate in perforated grid block (17, 10, 6) in production well for different scenarios and the same results of calcium carbonate can be observed for strontium sulphate.

Fig. 40 shows the mass fraction of chlorine ion in the producing water. Chlorine concentration in the formation
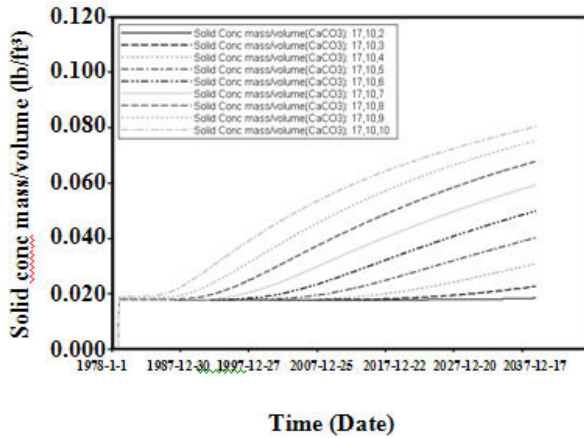
Fig. 23: Calcium Carbonate Deposition in Different Perforated Grid Blocks of Production Well in Scenario No. 2.
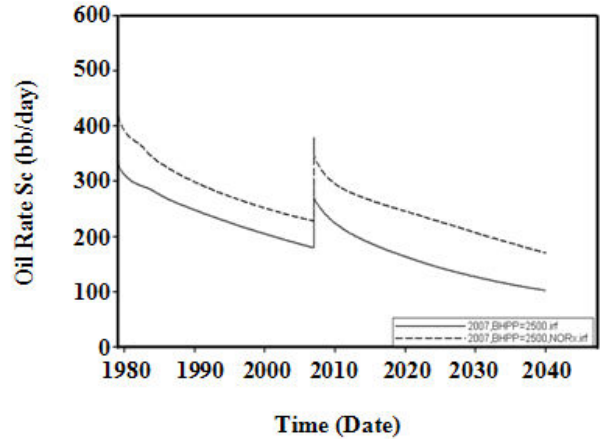

Fig. 26: Effect of Scale Deposition on Oil Rate in Scenario No. 3.
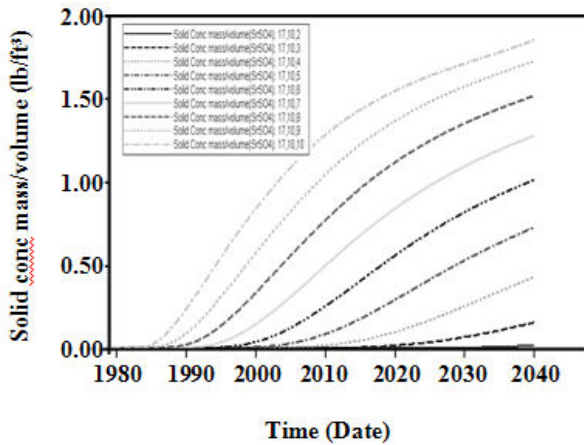

Fig. 24: Strontium Sulphate Deposition in Different Perforated Grid Blocks of Production Well in Scenario No. 2.
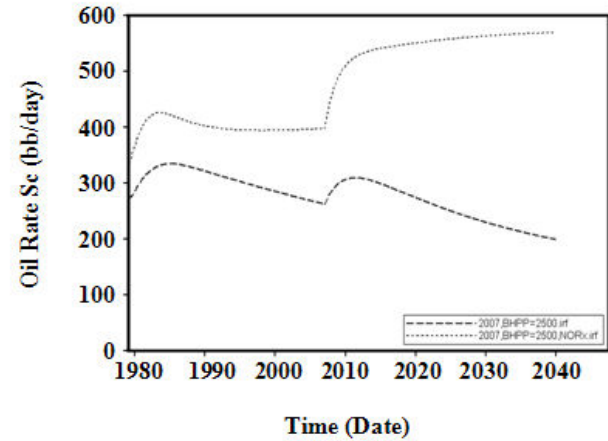

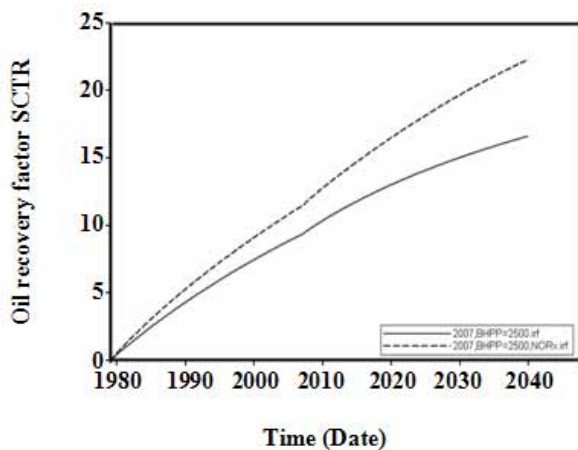**Fig. 27: Effect of Scale Deposition on Water Injection Rate in Scenario No. 3.**

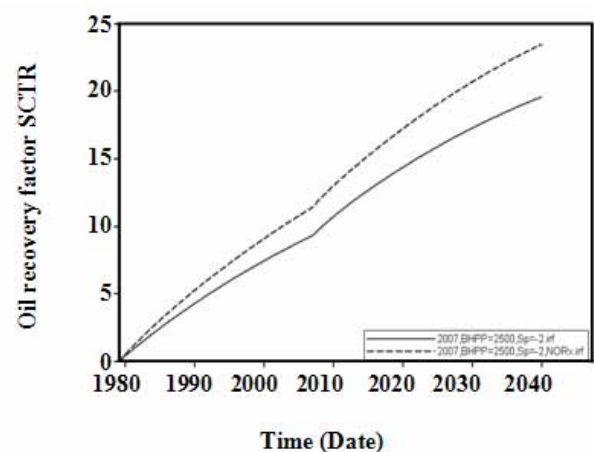**Fig. 25: Effect of Solid Deposition on the Oil Recovery in Scenario No. 3.**

Fig. 28: Effect of Solid Deposition on Oil Recovery in Scenario No. 4.
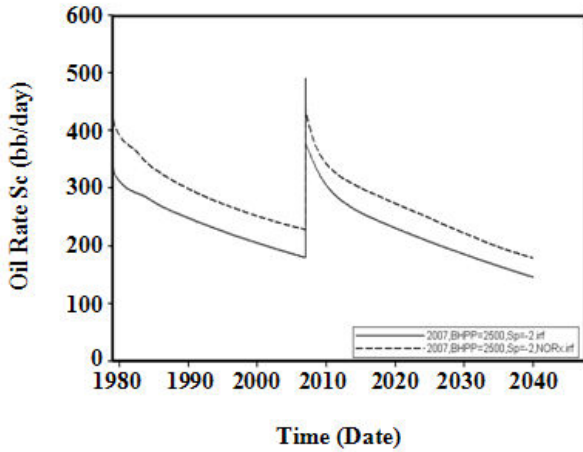
Fig. 29: Effect of Scale Deposition on Oil Rate in Scenario No. 4.
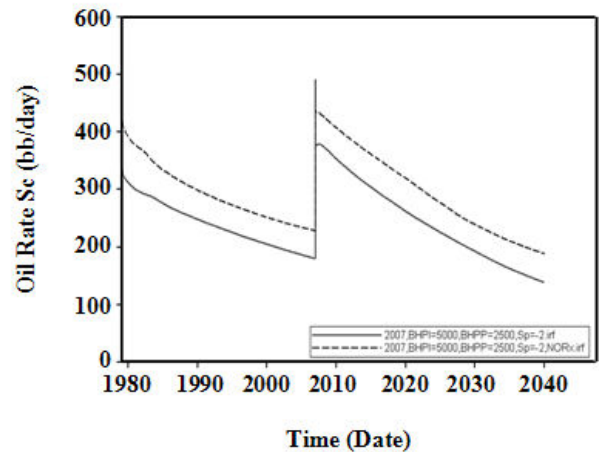
Fig. 32: Effect of Solid deposition on Oil Rate in Scenario No. 5.
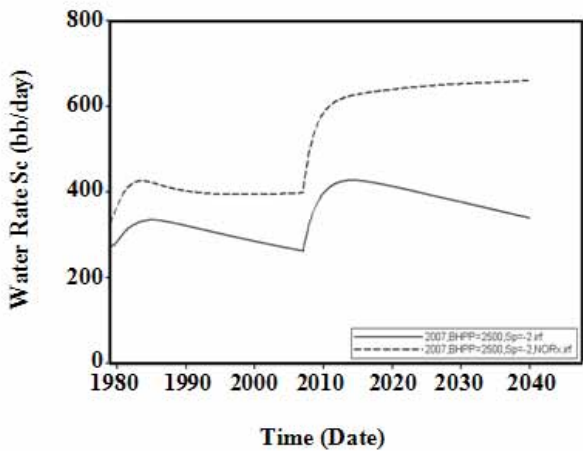

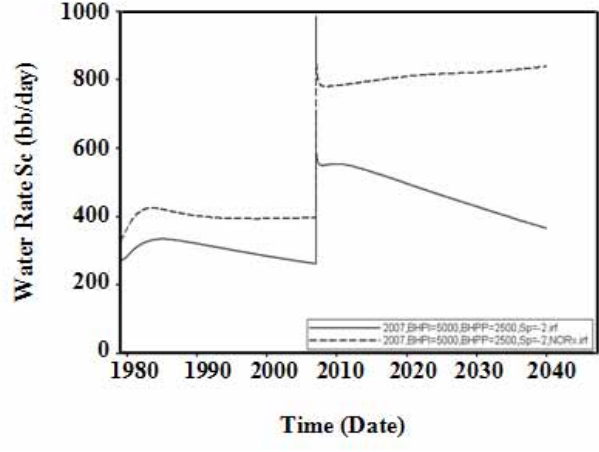***Fig. 30: Effect of Scale Deposition on Water Injection Rate in Scenario No. 4.***

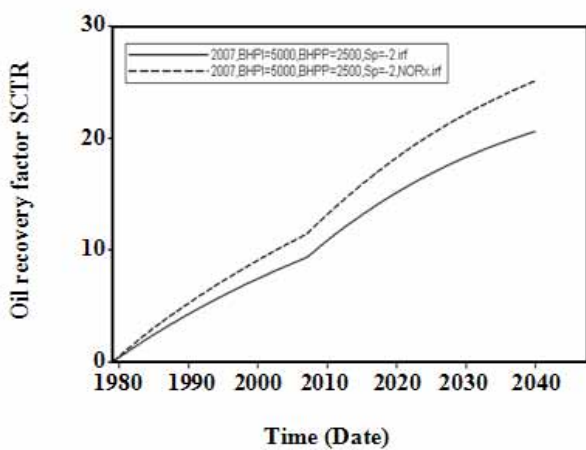***Fig. 33: Effect of Scale Deposition on Water Injection Rate in Scenario No. 5.***

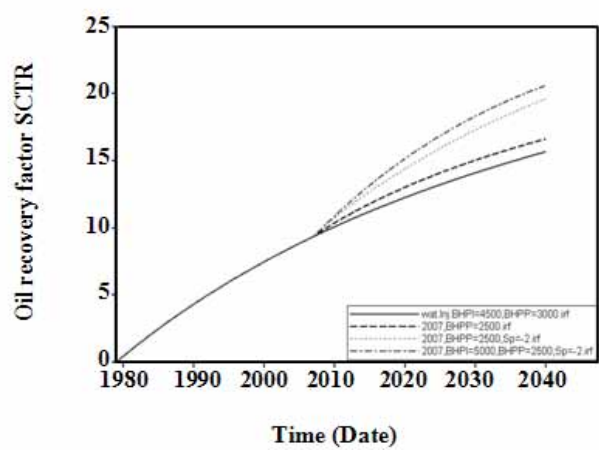***Fig. 31: Effect of Solid Deposition on Oil Recovery in Scenario No. 5.***

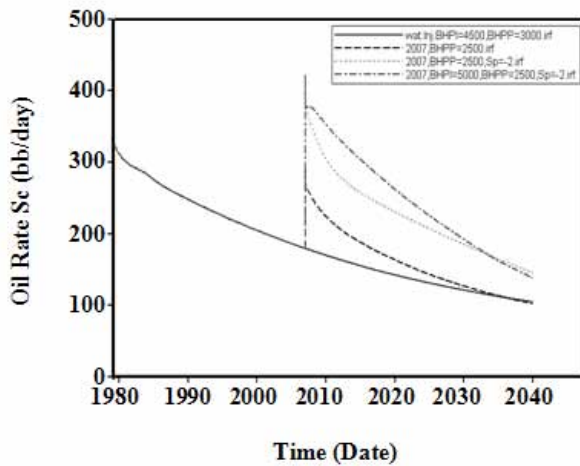***Fig. 34: Oil Recovery for Different Scenario.***

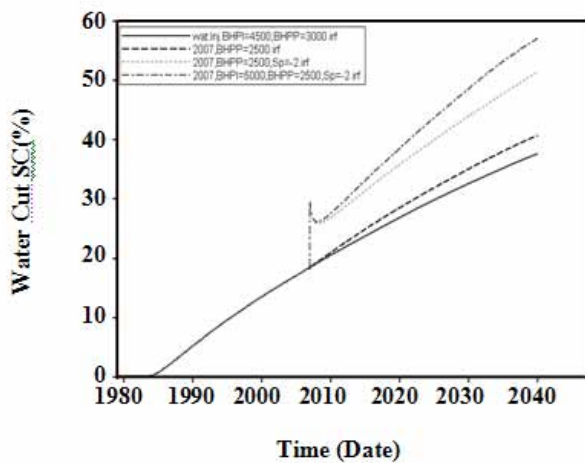*Fig. 35: Oil Rate for Different Scenarios.*

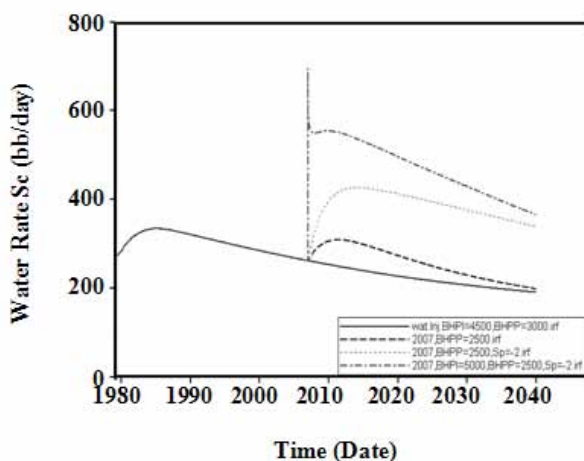*Fig. 36: Wate -cut for Different Scenarios*

Fig. 37: Water Injection Rate for Different Scenarios.

water was about 74000 ppm and in the injected water is 23000 ppm. It can be used as tracer for determination of the amount of injected water in every block, producing water and mixing zone in the reservoir. Fig. 40 illustrates that for all the cases, sea water front and therefore mixing zone do not reach to the production well because of low permeability of reservoir and so the solid precipitation around production well is almost because of pressure reduction and large volumes of water which has passed through the production wellbore. But along the path of injecting well to producing well, mixing and consequently incompatibility plays a main role of scale deposition.

CONCLUSIONS

The results obtained in this study are summarized as follow:

1- Based on experimental and theoretical studies, strontium sulphate and calcium carbonate are the main mineral scales that have tendency of deposition due to incompatibility between waters and pressure drop during sea-water injection process in Sirri-C oil field.

2- Deposition of mineral scales in Sirri-C oil field reduces oil recovery considerably. So this phenomenon should be considered for future plans.

3- Defining equilibrium K values in CMG-STARS gives more reliable results of scale deposition in deep of the reservoir ,as well as around the wells.

4- Any kinds of processes which cause pressure reduction near production well or increasing of producing water rate will increase the amount of scale deposited in the area near production wellbore.

5- Using pump in production well, acidizing of production well and increasing the injection bottomhole pressure will increase oil recovery, oil rate, water- cut and water injection rate in cases with and without considering scale deposition.

6- The acidizing operation of production well has the greatest positive effect on the oil recovery, oil rate, water- cut and water injection rate.

7- Using pump in production well will not have any considerable effect on the amount of deposited Strontium Sulphate and calcium carbonate around perforations in production well while acidizing of production well and increasing the injection well bottomhole pressure will increase the amount of these two scales around the production wellbore considerably.
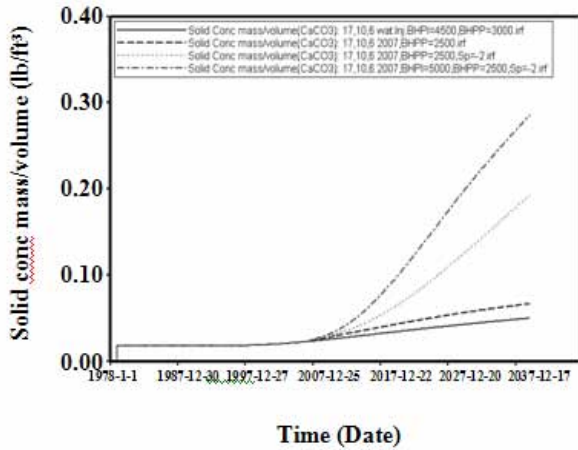
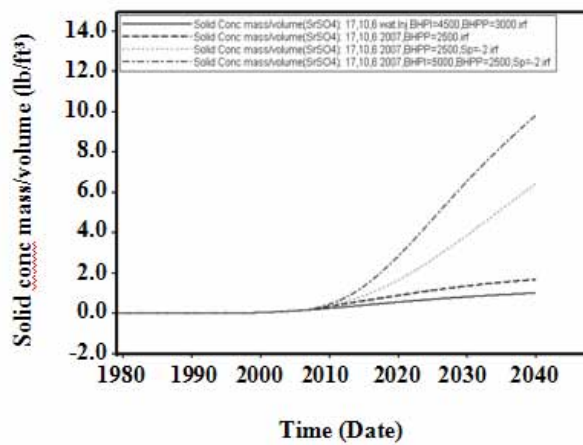***Fig. 38: Deposited Calcium Carbonate in Perforated Grid Block (17, 10, 6) for Different Scenarios.***

Fig. 39: Deposited Strontium Sulphate in Perforated Grid Block (17, 10, 6) for Different Scenarios.
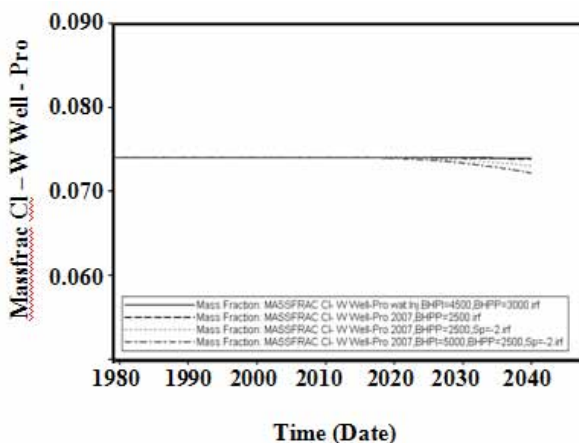

Fig. 40: Chlorine Concentration in the Produced Water as an Indicator of Mixing Zone.

8- Increase of strontium sulphate and salcium carbonate deposition due to acidizing of production well is more than the other scenarios because producing water rate increases more for this scenario.

9- Amount of the mineral scale deposition near the production well is more than the other regions in the reservoir. This is because of pressure dependency of scale deposition phenomena.

10- Using chlorine ion as tracer, it can be concluded that mixing zone do not reach to the production well for all the cases and so the solid precipitation around production well is almost because of pressure reduction and large volumes of water which has passed through the production wellbore.

Acknowledgement

Nomenclature

Cs_j	Concentration of Solid Number j
eq.	Equilibrium condition
I	Molar Ionic Strength, M
K	Equilibrium K Value, Dimensionless
k_a	Absolute Permeability, md
k_{ro}	Oil Relative Permeability
k_{rw}	Water Relative Permeability
Ksp	Solubility Product, M 2
K_2	Second Disassociation Constant for Carbonic Acid, M
m_i	Molal or Molar Concentration of each Component in the Solution
P	Pressure, psia
P_{cow}	Capillary Pressure (Oil/Wwater), psia
$RRSFT_j$	Residual Resistance Factor of Solid Number j
SI	Scaling Index, Dimensionless
S_w	Water Saturation, Fraction
T	Temperature, °F
TDS	Total Dissolved Salts, mg/L
Zi	Charge on Each Component in the Solution

SI Metric Conversion Factors

°F	(°F-32)/1.8 °C
psi	* 6.894757 = kPa

Appendix A: Ionic Strength Calculation

Below formula can be used for calculation of ionic strength:

$$I = \sum 1/2 m_i\, z_i^2 \tag{A.1}$$

Appendix B: Ksp Calculation of Strontium Sulphate and Calcium Carbonate

The following equation has been suggested for calculation of strontium sulphate Ksp[9]:

$$pKsp = 6.11 + 2\times10^{-3}T + 6.4\times10^{-6}T^2 - \tag{B.1}$$
$$4.6\times10^{-5}\,P - 1.89\times I^{1/2} + 0.6I - 1.9\times10^{-}I^{1/2}T$$

The following equations have been suggested for calculation of K_2 and calcium carbonate Ksp [15]:

$$pK_2 = 10.61 - 4.97\times10^{-3}T + 1.331\times10^{-5}T^2 - \tag{B.2}$$
$$2.624\times10^{-5}p - 1.166I^{1/2} + 0.3466I$$

$$pKsp = 7.82 + 6.46\times10^{-3}T + 8.59\times10^{-6}T^2 - \tag{B.3}$$
$$7.00\times10^{-5}p - 3.21\times I^{1/2} + 1.073I$$

where;
$pKsp = -\log Ksp$

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