Technology for prediction of salt deposition in oil production

L E Lenchenkova¹, L Z Zainagalina², N D Bulchaev¹, Yu A Kotenev¹, F Z Bulyukova¹ and A R Safiullina²

¹ Ufa State Petroleum Technological University, 1, Kosmonavtov St., Ufa, Republic of Bashkortostan, 450062, Russian Federation
² Ufa State Petroleum Technological University, Branch of the University in the City of Oktyabrsky, 54a, Devonskaya St., Oktyabrsky, Republic of Bashkortostan, 452607, Russian Federation
³ Grozny State Oil Technical University named after Academician M.D. Millionshchikov, 100, Kh.A. Isaev prospect, Grozny, Chechen Republic, 364051, Russian Federation

E-mail: lenchenkova1@mail.ru, info@of.ugntu.ru

Abstract. The formation of inorganic salts in the bottom-hole area leads to a deterioration of the reservoir filtration properties and a decrease in the productivity of oil wells. The conducted research shows that the decrease in rock permeability due to salt deposition during flooding mainly depends on the number of filtered pore volumes of the injected solution, the rate of injection, temperature, differences in pressure, initial permeability of the rock and the concentration of the solution. The development of an empirical formula for predicting salt deposits in the bottom-hole area and describing the dependence of rock permeability on these factors involves the use of reliable experimental and field data. The authors propose a method for determining the probability of precipitation of some inorganic salts in the well.

1. Introduction
A fundamental part of evaluating an oil field to control salt deposition is to predict the possibility and intensity of salt deposition and determine sedimentation during oil production. Prediction of hard mineral precipitation is one of the ways to control salt deposition. Therefore, it is necessary to forecast the conditions of salt deposition in the oil industry. The first stage of salt deposition control is the analysis of waters to determine their propensity to form salt deposits. Thus, to make a predictive assessment of salt deposition, it is necessary to know the chemical composition of water and the thermobaric conditions of the formation.

2. Materials and methods
There are many models for determining the probability of salt deposition. Available models for predicting salt deposition conditions are based on thermodynamic data on limited solubility [4, 10]. The corresponding thermodynamic model should determine the type of salt formed and the maximum amount of precipitation when mixing the injected and reservoir water. Determining the probability of precipitation of some inorganic salts in the well requires the use of reliable experimental and field data. The method proposed by the authors consists of developing an empirical formula for predicting salt deposits in the bottom-hole area and describing the dependence of rock permeability on the
number of filtered pore volumes of the injected solution, the injection rate, temperature, pressure drop, initial rock permeability and solution concentration. The authors have developed a model based on multi-factor correlation and regression analysis for predicting a decrease in the permeability of BHA as a result of the deposition of mineral deposits (barium sulfate).

3. Results and Discussion

In [2], the ability of water to precipitate in oilfield equipment was determined by calculating the stability of injected and reservoir water based on the Stief-Davis approach. The saturation index (SI) of water with salts (calcium carbonate, barium sulfate, calcium sulfate, and strontium sulfate) was first proposed by Oddo and Thomson [6]. The proposed water salt saturation index was a polynomial equation that was a function of temperature, pressure, and ionic force. When determining the water saturation index with calcium carbonate, the concentration of carbon dioxide (CO2) in the solution was included in the formula. In [8], we present models and semi-empirical relationships based on experimental data that could determine the statistical probability of the formation of insoluble salts when water is injected into the reservoir using the saturation index. In [3], we have successfully determined the probability of precipitation of calcium carbonate in the system of reservoir pressure maintenance by applying a model based on the saturation index when mixing incompatible waters in the aquifer. Models often present the effect of temperature, pressure, and pH of the solution on the intensity of salt deposition. Thus, the possibility and prediction of the formation of salt deposits in static conditions are calculated by the saturation index specified in the following formula [6, 9]:

$$SI = \log\left(\frac{[Ca][An]}{K}\right),$$

where SI is the saturation index, a dimensionless value; [Ca] and [An] are square brackets representing the molar concentration of cations and anions, mol/l; Ksp is the product of solubility at equilibrium, mol/l.

In formula (1), the numerator (the product of two concentrations) is an indicator of ion activity. Ksp depends on the thermobaric conditions and the ionic strength of the solution (I), expressed as follows [8]:

$$pK_{sp} = -\log(K_{sp}),$$

$$SI = -\log(([Ca][An]) + pK_{sp},$$

$$pK_{sp} = a_1 + a_2 T + a_3 T^2 + a_4 P + a_5 I^{0.5} + a_6 I^{0.5} T + a_7 I,$$

$$(4)$$

$$SI = \log((Ca)[An]) + a_1 + a_2 T + a_3 T^2 + a_4 P + a_5 I^{0.5} + a_6 I^{0.5} T + a_7 I,$$

$$(5)$$

where T is the temperature, °F; P is the pressure, per square inch (psi); a1, a2, a3, a4, a5, a6, and a7 are the empirical coefficients (Table 1), I is the ionic force, mol/l.

If SI>0, salt deposition occurs, and if SI<0, there is no risk of salt deposition [1].

Table 1 shows the values of the empirical coefficients for sulfate salts.

| Salt       | a1    | a2     | a3  | a4         | a5   | a6   | a7    |
|------------|-------|--------|-----|------------|------|------|-------|
| CaSO4·2H2O | 3.47  | 1.8·10^{-3} | 2.5·10^{-6} | -5.9·10^{-5} | -1.13 | 0.37 | -2.0·10^{-3} |
| CaSO4·H2O  | 4.04  | -1.9·10^{-3} | 11.9·10^{-6} | -6.9·10^{-5} | -1.66 | 0.49 | -0.66·10^{-3} |
| CaSO4      | 2.52  | 9.98·10^{-3} | -0.97·10^{-6} | -3.07·10^{-5} | -1.09 | 0.50 | -3.3·10^{-3} |
| SrSO4      | 6.11  | 2.0·10^{-3}  | 6.4·10^{-6}  | -4.6·10^{-5}  | -1.89 | 0.60 | -1.9·10^{-3} |
| BaSO4      | 10.03 | -4.8·10^{-3} | 11.4·10^{-6} | -4.8·10^{-5}  | -2.62 | 0.89 | -2.0·10^{-3} |
| MgSO4      | 2.30  | 1.74·10^{-3} | 4.55·10^{-6} | -7.8·10^{-6}  | 2.28  | -0.46 | -0.60·10^{-3} |

For calcium carbonate the saturation index is defined as follows:
SI = lg([Ca^{2+}][CO_3^{2−}]) + pH − 2,76 + 9,88 \times 10^{-3}T + 0,61 \times 10^{-6}T^2 − 3,03 \times 10^{-5}p − 2,348l^{0,5} + 0,77l \quad (6)

When determining the water saturation index of calcium carbonate by formula 6, the value of the hydrogen index is determined depending on the presence or absence of a gas phase in the system. However, it is difficult to determine the exact value of the hydrogen index due to theoretical and practical limitations [5].

There are various software applications for predicting hard mineral precipitation and getting an idea of the chemical equilibrium that characterizes water systems. The computer program provides the prediction of salt deposition based on thermodynamics for determining physical and chemical properties in multiphase water systems. This basis applies to most multicomponent mixtures and allows predicting the likely possibility of salt deposition at any values of temperature, pressure, and ion concentration. Some authors have developed a computer program for predicting the probable possibility of salt deposition and determining the water saturation index by applying reservoir temperature and pressure.

To determine the effect of the liquid-vapour equilibrium on the intensity of salt deposition, the PHREEQC program was used, which simulates the conditions of salt deposition during degassing with different initial concentrations of dissolved gas. They concluded that it is necessary to choose the best liquid-vapour equilibrium model for simulating the prediction of salt deposition, especially in the presence of gas mixtures. Some programs give values for the tendency to form salt deposits (the ability of water to form deposits). However, the tendency to form salt deposits (ST) and the saturation index (SI) of water are strongly related to each other. There is the following relationship between them:

\[ SI = \lg(ST) \] \quad (7)

To predict changes in rock permeability due to salt deposition, it is necessary to develop a complex correlation, which is the parameters that affect the degree of deterioration of the reservoir properties of the BHA. Many scientists have studied the deposition of inorganic salts in porous media to develop mathematical models that can predict a decrease in the permeability of rocks in reservoir conditions. The development of models to describe the process of salt deposition in a porous medium when mixing reservoir and injected water, including dispersion/diffusion modelling, leads to the prediction of salt deposition in the BHA.

Since the process of salt deposition is caused by the mixing of two liquids, it is necessary to determine the main parameters in the "reaction-diffusion-advection" control to develop an asymptotic model to determine the deposition rate in porous media. The resulting model can be compared with a numerical model to verify the accuracy of the prediction of a decrease in the permeability of the BHA due to salt deposition. Based on the laboratory data, some empirical formulas are proposed for predicting the decrease in permeability due to salt deposition during flooding. Most of these studies focused on only one type of salt during the water injection process. Some authors have developed a mathematical model [11, 12] for predicting a decrease in permeability due to simultaneous deposition of several types of inorganic salts based on thermodynamics, kinetics and hydrodynamics when a liquid moves in a porous medium. It was also noted that obtaining laboratory data on the formation of salt deposits makes it possible to increase the accuracy of predicting the precipitation of solid mineral precipitation in porous media.

Modelling the deposition of one type of salt is not a difficult task, but the simultaneous deposition of several types of salts and, respectively, the modelling of these processes is a difficult task due to the complexity of the water system and the interaction of different ions during salt deposition. The complexity of the crystallization process limits most of the developed models for porous media since the deposition of one salt does not pay enough attention to the co-deposition of other salts, especially those that have common ions. In the presence of several types of salts and their co-deposition in porous media, each salt is deposited according to its scenario, which differs from the others. Therefore, the developed models for predicting the risk of deterioration of the permeability of the BHA as a result of precipitation of a single salt can not give correct results when several salts fall out.
simultaneously. This happens mainly because the co-deposition of inorganic salts and the formation of their mixture affect the thermodynamic and kinetic behaviour of each salt in the mixture. Deposits in oil fields are rarely pure and often occur as mixtures of two or more inorganic compounds with the presence of paraffin, silicon dioxide, or some other impurities. They further complicate the process of salt deposition and, respectively, the development of technological schemes to control them.

The conducted research shows that the decrease in rock permeability due to salt deposition during flooding mainly depends on the number of filtered pore volumes of the injected solution, the rate of injection, temperature, pressure drop, initial permeability of the rock and the concentration of the solution. The development of an empirical formula for predicting salt deposits in BHA and describing the dependence of rock permeability on these factors involves the use of reliable experimental and field data. However, the accurate measurement of experimental data is almost impossible, and some incorrect and undesirable measurements can still lead to significant distortions of the results.

Recently, a new model has been proposed using the MATLAB program based on an annealing simulation algorithm to predict the decrease in the permeability coefficient caused by the deposition of inorganic salts in porous media. In [7], the authors conducted some experimental and theoretical studies to examine the decrease in permeability due to the deposition of calcium sulfate in porous media. It is emphasized that when studying the decrease in permeability as a result of salt deposition, it is necessary to systematically take into account various important parameters that affect this complex process to one degree or another. A new formula with high accuracy for determining the permeability coefficient as a result of the formation of salt deposits is proposed. The formula developed by the authors is based on data obtained in models of carbonate-type cores at low pressures. A slight difference between the standard deviations of the formula and the experimental data confirms the validity of the formula. The developed formula for estimating the decrease in permeability of a porous medium is expressed by the following equation [7]:

$$\frac{K_C}{K_I} = \exp \left(-PV_{inj} \frac{f_0A[I_{160}(C_{sat}-1)]^2}{bq} \right),$$

(8)

where $K_C$ – the current permeability (after salt deposition), microns; $K_I$ – the initial sample permeability, microns; $PV_{inj}$ – number of filtered pore volumes, m/m; $f_0$ – the initial core porosity, unit fraction; $A$ – the cross-sectional area, cm$^2$; $T$ – temperature, °C; $C_{sat}$ – the degree of saturation of water with calcium sulfate, unit fraction; $b$ – the empirical coefficient, min/cm; $q$ – the rate of injection, cm$^3$/min.

4. Conclusion

The authors have developed a model based on multi-factor correlation and regression analysis for predicting a decrease in the permeability of BHA as a result of the deposition of mineral deposits (barium sulfate). The model is developed after analyzing experimental data and statistical analysis, and is interpreted as follows:

$$\exp \left(\frac{K_C}{K_I} \right) = b_1 + b_2T^{0.17} + b_3(qt)^{0.25} + b_4 \ln(V_{pore}) + b_5 \ln(C_k) + b_6 \ln(\Delta P).$$

(9)

where $K_C$ is the current permeability of the sample (after salt precipitation), microns; $K_I$ is the initial permeability of the sample, microns; $b_1, b_2, b_3, b_4, b_5,$ and $b_6$ are the empirical coefficients the values of which depend on the concentration of barium; $T$ – the reservoir temperature, °F; $q$ – injection rate, ft/min; $t$ – the time of injection, min; $V_{pore}$ – the volume of pore space, cubic ft; $C_k$ is the concentration of barium sulfate, mg/l; $\Delta P$ – the differential pressure, pound per square inch (Pa).

The statistical analysis of the results shows that at medium and high concentrations of barium, the model accurately estimates the decrease in rock permeability with determination coefficients of 0.941 and 0.948, respectively. The analysis of graphical errors also shows that the model corresponds to experimental data.

References

[1] Garda A V, Thomsen K and Stenby E H 2006 Prediction of Mineral Scale Formation in
Geothermal and Oilfield Operations Using the Extended UNIQUAC Model: Part II. Carbonate-Scaling Minerals Geothermics 35(3) 239-284. DOI: http://dx.doi.org/10.1016/fgeothermics.2006.03.001

[2] Rogachev M K and Mukhametshin V V 2018 Control and Regulation of the Hydrochloric Acid Treatment of the Bottom-Hole Zone Based on Field-Geological Data J. of Mining Institute 231 275-280. DOI: 10.25515/PMI.2018.3.275.

[3] Zainagalina L Z, Suleimanov R I, GAbrakhimov M S and Khabibullin M Y 2018 Determining Oscillating System Dynamic Parameters of a Near-Bit Junk Pulper Advances in Engineering Research 157 642-645

[4] Shaidullina R M, Amirov A F, Muhametshin V Sh and Tyncherov K T 2017 Designing Economic Socialization System in the Educational Process of Technological University European J. of Contemporary Education 6(1) 149–158. DOI: 10.13187/ejced.2017.1.149

[5] Tahmasebi H A, Kharrat R and Soltanieh M 2010 Dimensionless Correlation for the Prediction of Permeability Reduction Rate due to Calcium Sulphate Scale Deposition in Carbonate Grain Packed Column J. of the Taiwan Institute of Chemical Engineers 41(3) 268-278. Retrieved from: http://dx.doi.org/10.1016/i.itice.2009.11.006

[6] Khabibullin M Ya, Samigullina L Z and Zainagalina L Z 2018 Laboratory Studies for the Momentum of Liquid Optimal Impact on Hydro-Carbon Formation Advances in Engineering Research 157 276-279

[7] Jordan M M, Kemp S, Sorhaug E et al 2003 Effective Management of Scaling From and Within Carbonate Oil Reservoirs, North Sea Basin Chemical Engineering Research and Design 81(3) 359-372. Retrieved from: http://dx.doi.org/10.1205/02638760360596919

[8] Stenkin A V, Kotenev Yu A, Muhametshin V Sh and Sultanov Sh Kh 2019 Use of Low-Mineralized Water for Displacing Oil From Clay Productive Field Formations IOP Conf. Ser.: Mater. Sci. Eng. 560(1) 012202. DOI: 10.1088/1757-899X/560/1/012202

[9] Almukhametova E M, Shamsutdinova G F, Sadvakasov A A, Tyncherov K T, Petrova L V and Stepanova R R 2018 Modelling development of Fyodorovsky deposit IOP Conf. Ser.: Mater. Sci. Eng. 327(4) 042100. DOI: 10.1088/1757-899X/327/4/042100.

[10] Kan A T and Thomson M B 2012 Scale Prediction For Oil and Gas Production SPE J. 17(2) 362-378. Retrieved from: http://dx.doi.org/10.2118/132237-PA

[11] Kuleshova L S, Kadyrov R R, Mukhametshin V V and Safiullina A R 2019 Design Changes of Injection and Supply Wellhead Fittings Operating in Winter Conditions IOP Conf. Ser.: Mater. Sci. Eng. 560(1) 012072. DOI: 10.1088/1757-899X/560/1/012072

[12] Kuleshova L S, Kadyrov R R, Mukhametshin V V and Akhmetov R T 2019 Auxiliary Equipment for Downhole Fittings of Injection Wells and Water Supply Lines Used to Improve Their Performance in Winter IOP Conf. Ser.: Mater. Sci. Eng. 560(1) 012071. DOI: 10.1088/1757-899X/560/1/012071