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Improving sweep efficiency of edge-water drive reservoirs using induced formation damage

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ABSTRACT

A common problem in edge-water drive reservoirs is oil bypassing by aquifer water. The encroaching water from the adjacent aquifer overtakes oil phase and leaves a significant volume of trapped residual oil behind. Early arrival of these water fingers causes pre-mature water production that leads to well abandonment. One solution to the problem is creating a barrier against the encroaching water. In current study the possibility of using induced formation damage caused by injecting a small volume of low salinity water into abandoned wells is investigated. Formation damage as a result of injection of low salinity water into the watered-up wells creates a low permeable barrier against the water fingers. The methodology of modeling this technique using a commercial reservoir simulator is presented. The modeling results show that injection of small volume of low salinity water results in prolongation of wells' life which results in \sim 3–5% incremental recovery if compared to normal depletion.

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1. Introduction

On average, more than three barrels of water is produced for each barrel of oil and it costs billions of dollars every year to dispose the unwanted water (Bailey et al., 2000). Many oil reservoirs derive their natural producing energy from adjacent aquifers. Oil bypassing due to water invasion is a major problem in edge-water drive reservoirs. In edge-water drive reservoirs, water tongue may underrun oil causing early water production at the well and low productivity of the oil with considerable unrecovered oil left behind (Hernandez and Wojtanowicz, 2006). Encroachment of edge-water results in pre-mature water production from wells low on structure and early termination of wells' life. The water production continues to increase until the economic limit of WOR of the well is reached. At the time of abandonment, there may be considerable unswept oil still trapped behind the water front. Depending on the reservoir heterogeneity, the residual oil saturation may reach 60% (Kumar, 1977; Braedley, 1987; Hernandez et al., 2006). Hence, it is of a great interest to ascertain ways to retard the water encroachment and control early water production and bypassed oil in edge-water drive reservoirs. Many different methods are used to slow down the water tongue including: production rate control, management of the total oil production pattern and injection of barrier fluids. Most commonly

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http://dx.doi.org/10.1016/j.petrol.2015.04.008 0920-4105/© 2015 Elsevier B.V. All rights reserved. used barriers fluids are cement, gels, resins, foams and polymers (Karp et al., 1962; Seright et al., 2001; Zaitoun and Pichery, 2001). A large treatment volume is required to divert water away from the area that has been already swept by water, which is generally uneconomic (Bailey et al., 2000).

Reduction of rock permeability due to low salinity water injection has been observed in several laboratory and field studies (Mungan, 1965; Khilar et al., 1983; Lever and Dawe, 1984). It is explained by mobilization of in-situ fines and subsequent plugging of pore throats. Naturally in-situ fine particles are initially in mechanical equilibrium of drag, lifting, electrostatic and gravitational forces. Injection of low salinity water weakens the electrostatic force and perturbs the equilibrium of the particle on pore wall. As a result the fine particles are dragged with the flowing water and block narrow pore throats (Khilar and Fogler, 1998; Ochi and Vernoux, 1998; Bedrikovetsky et al., 2012; Hussein et al., 2012). Mobilization of fine particles and subsequent pore plugging results in permeability reduction when low salinity water is injected. Bedrikovetsky et al. (2012) introduced maximum retention function for modeling of fines migration in porous media. The proposed approach allows applying the torque balance of forces on single particle to calculate the maximum concentration of particles that can remain in a porous medium. The validity of this approach was confirmed by comparison with serious of directly measure core data (Lemon et al., 2011; Zeinijahromi et al., 2011; Hussein et al., 2012). The permeability reduction values of 40-100 times has reported in various laboratory experiments (Mungan, 1965; Khilar et al., 1983; Lever and Dawe, 1984; Sarkar and Sharma, 1990;

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Latin letters γ γ^0 brine ionic strength, molL ⁻³ , mol/l ionic strength of the injected brine, molL ⁻³ , mol/l γ^0 cconcentration of suspended particles γ^0 γ^0 ionic strength of the injected brine, molL ⁻³ , mol/l γ^0 c_apolymer adsorption concentration γ^0 γ^0 ionic strength of the injected brine, molL ⁻³ , mol/l γ^0 γ^0 polymer concentrations in the aqueous phase γ^0 μ_o oil dynamic viscosity, ML ⁻¹ T ⁻¹ , cp μ_w γ^0 polymer concentrations in the injected water γ^0 β formation damage coefficient γ^0 γ^0 reservoir ratio (erosion number) γ^0 γ^0 γ^0 gravitational force, MLT ⁻² , N σ volumetric concentration of captured particles γ^0 reservoir initial absolute permeability, L ² , mD σ_a initial volumetric concentration of attached particles κ_ro oil relative permeability σ_s volumetric concentration of strained particles	Nomenclature	Greek letters
R_{rw} water feative permeability l_d lever for drag force, L, m l_n lever for normal force, L, m p pressure, $ML^{-1}T^{-2}$, Pa R_k resistance factorSwater saturatinUoverall flow velocity, LT^{-1} , m/s	Latin letterscconcentration of suspended particles c_a polymer adsorption concentration c_p polymer concentrations in the aqueous phase c_p^0 polymer concentrations in the injected water F_d drag force, MLT ⁻² , N F_e electrostatic force, MLT ⁻² , N F_g gravitational force, MLT ⁻² , N F_1 lifting force, MLT ⁻² , N K_i absolute permeability, L ² , mD k_o initial absolute permeability, L ² , mD k_{ro} oil relative permeability k_{rw} water relative permeability l_d lever for drag force, L, m l_n lever for normal force, L, m p pressure, ML ⁻¹ T ⁻² , Pa R_k resistance factor S water saturatin U overall flow velocity, LT ⁻¹ , m/s	$\begin{array}{lll} \gamma & \mbox{brine ionic strength, molL^{-3}, mol/l} \\ \gamma^0 & \mbox{ionic strength of the injected brine, molL^{-3}, mol/l} \\ \gamma_i & \mbox{reservoir initial brine ionic strength, molL^{-3}, mol/l} \\ \mu_o & \mbox{oil dynamic viscosity, ML^{-1}T^{-1}, cp} \\ \mu_w & \mbox{water dynamic viscosity, ML^{-1}T^{-1}, cp} \\ \beta & \mbox{formation damage coefficient} \\ \varepsilon & \mbox{torque ratio (erosion number)} \\ \sigma & \mbox{volumetric concentration of captured particles} \\ \sigma_a & \mbox{volumetric concentration of attached particles} \\ \sigma_{cr} & \mbox{maximum volumetric concentration of strained particles} \\ \sigma_s & \mbox{volumetric concentration of strained particles} \\ Abbreviations \\ LSW & \mbox{low salinity water} \\ \end{array}$

Hussein et al., 2012); that motivates application of low salinity water injection as a possible method to create a barrier against water tongue in edge-water reservoirs (Nguyen et al., 2013).

Modeling results by Nguyen et al. (2013) have shown that injection of small volume low salinity water (LSW) into abandoned wells can reduce the encroaching water velocity and enhances the ultimate sweep efficiency by 15–18%. The current study follows on from the method of applying low salinity water injection to control water encroachment by Nguyen et al. (2013). Whilst this earlier work has studied the method of creating barrier against aquifer water tongue, it assumed a simplified two dimensional reservoir model. The current paper extends the previous work (Nguyen et al., 2013) addressing 3D five spot pattern which is commonly used in field developments to increase the areal sweep efficiency.

The current work follows Bedrikovetsky et al. (2012) in modeling particle detachment during low salinity water injection. Thus the maximum retention function is applied to model the fines detachment due to injection of alternating brine salinity when non-swelling mobile clay fines are present. In current paper the approach by Zeinijahromi et al. (2013) is applied to implemented Eclipse black oil simulator (Schlumberger, 2013) in order to model low salinity water flow with induced fines migration. Zeinijahromi et al. (2013) developed a new method for implementing commercial reservoir simulators to model water injection with induced fines migration. From practical point of view, the advantage of the method is that it can be readily incorporated into the existing polymer simulator to model low salinity water injection without the need for developing new software or modifying the current simulators.

2. Induced formation damage method to decelerate edgewater encroachment

In this section the concept of using permeability decline by low salinity water injection to create low permeability barrier against the encroaching edge-water is discussed. Fig. 1a shows a schematic for encroachment of edge-water during oil production with full or partial pressure maintenance by the aquifer at different stages of the field development. The light blue and red colors represent water and oil respectively and black line shows aquifer water front. Water from the adjacent aquifer (purple arrows) encroaches into the oil reservoir due to pressure drop between the aquifer and the production wells. At the moment t_1 , minimum pressure during water-driven production is reached near to production wells; hence the stream lines from the aquifer cross the location points for wells low on structure. Thus, the central lines of the water tongues also cross the location points for structurally low wells. The low structure wells are abounded at some high water-cut value, when the cost of water production and disposal exceeds the economical limit. Pressure builds up near the low structure producers after their closure; thus, minimum pressures over the area are reached near the high structure producing wells (moment t_2). Water tongues continue to move towards the wells high on structure and leave a significant volume of residual oil behind. Fig. 1b shows the similar scenario of oil production with the short-term LSW injection in the abandoned wells. Similar to the 'normal' production scenario, at the moment t_1 minimum pressure reaches near to wells low on structure and the pressure gradients from the aquifer cross the location points for wells low on structure causing water tongues to cross these wells. A small volume of low salinity water is injected into structurally low wells after they have reached the economical limit of water production. It induces permeability reduction due to fines migration and creates a low permeable zone in well vicinity (dark blue area around structurally low wells). The created low permeable zone can slow down the water fingers from moving towards up-structure producers. It homogenizes movement of water front and prolongs water-free production period of wells high on structure that leads to the ultimate recovery improvement.

3. Physic mechanisms of induced formation damage

Several studies have shown that low salinity water injection into reservoirs rocks can cause reduction of rock permeability. The phenomenon is explained by mobilization of reservoir fines which plug the narrow pore constriction (Khilar and Fogler, 1998; Ochi and Vernoux, 1998; Bedrikovetsky et al., 2011). The mechanical equilibrium of an attached particle is determined by torque balance of four major forces; drag force, lifting force, gravitational force and total electrostatic forces (Fig. 2).

$$F_d(U)l_d + F_l(U)l_n = (F_e(\gamma) + F_g)l_n \tag{1}$$

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Fig. 1. Schematic for induced formation damage method to decelerate edge-water encroachment: (a) normal pressure depletion and (b) pressure depletion followed by induced formation damage. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)



Fig. 2. Forces acting on an attached particle.

Here, γ is salt concentration and *U* is the Darcy velocity, l_d and l_n are lever arms for drag and normal forces, respectively.

Left hand side of Eq. (1) defines the detaching torque of drag and lifting forces while right hand side shows the attaching torque by gravitational and electrostatic force. The particle remains on the pore wall only if the mechanical equilibrium condition (Eq. (1)) on a particle is fulfilled i.e. the attaching torques is less than or equal to the detaching torque. If not, the hydrodynamic forces can dislodge the particle.

Hydrodynamic forces (drag and lifting force) depend on flow velocity, U (Saffmann, 1965; O'Neill, 1968); while, total electrostatic force is a function of particle and rock mineralogical compositions and also fluid composition (pH, salinity (γ) and temperature); see Israelachvili, 1992. The total electrical force is the sum of the van der Waals, electrical double layer and Born forces as described by the DLVO (Derjaguin, Landau, Verwey and Overbeek) theory (Derjaguin, 1989; Israelachvili, 1992; Khilar and Fogler, 1998). The total electrostatic force changes with particlesurface separation distance. Attaching torque is weakened with decrease of brine salinity which yields in increase of the separation distance. Increase of the flow velocity also has the same effect on separation distance by increasing the detaching torque. Electrostatic forces are short rage forces; hence, the fine particle remains attached to the surface, as long as the separation distance is smaller than that where the electrostatic force reaches maximum. Therefore, Eq. (1) expresses the condition of particle detachment for the maximum value of electrostatic force. Further in the text, F_e denotes the maximum value of the attaching electrostatic force.

Alternation of either flow velocity or fluid chemistry may result in perturbation of torque balance that can lead in particle dislodgment from the pore walls. Flow velocity increase results in higher detaching torque (see left hand side of Eq. (1)) and consequent particle mobilization if it exceeds the attaching torque (see right hand side of Eq. (1)). Similarly, decreasing salinity of brine causes the total electrical force to decrease which leads to mobilization of particle by hydrodynamic forces. Dimensionless erosion number ε is introduced as the ratio between the detaching and attaching torques

$$\varepsilon = \frac{F_d l_d + F_l l_n}{(F_e + F_g) l_n} \tag{2}$$

In-situ fines are not mobilized unless the torque from detaching forces is greater than that for attaching torque, i.e. the value of ε exceeds that corresponding to maximum electrostatic force, see Bedrikovetsky et al. (2012). Introducing the erosion number ε allows calculation of the maximum concentration of particles that can exist in a porous medium σ_a for each flow condition (velocity U and salinity γ).

$$\sigma_a = \sigma_{cr}(\varepsilon(U, \gamma)) \tag{3}$$

Fig. 3 shows the maximum retention concentration σ_a vs the erosion number. Reducing of salt concentration from formation water γ_i to injection water γ^0 perturbs the balance between attaching and detaching torque and results in fines release. The volume of released particles $\Delta \sigma$, is equal to the difference between initial concentration of attached particles $\sigma_{a0}(\varepsilon(\gamma_i))$ and maximum concentration of particles for injected fluid composition $\sigma_a(\varepsilon(\gamma^0))$, that can be determined using Eq. (3).

The distance that released particles travel before being captured at the pore constrictions is significantly smaller than reference reservoir size. It corresponds to instant straining of mobilized fine particle at large scale approximation implying that the volume of strained particles σ_s , is equal volume of released particles $\Delta \sigma$ during alternation of salinity from γ_i to γ^0 :

$$\sigma_{s}(\varepsilon(\gamma^{0})) = \Delta\sigma(\varepsilon(\gamma^{0})) = \sigma_{a0}(\varepsilon(\gamma_{i})) - \sigma_{a}(\varepsilon(\gamma^{0}))$$
(4)

Following Pang and Sharma (1997) and Mojarad and Settari (2007), it is assumed that the inverse to normalized permeability k (σ_s)/ k_0 is a linear function of the retained particle concentration:

$$\frac{k_0}{k(\sigma_s)} = 1 + \beta \sigma_s(\varepsilon) \tag{5}$$

where β is formation damage coefficient which shows the degree of damage due to pore plugging and k_0 is the initial (not damaged) rock permeability.

4. Mathematical model for two-phase flow with fines migration

Particle detachment takes place when detaching torque is greater than attaching torque in the pores which are occupied

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by low salinity water. Therefore, in this section the detachment of in-situ particles from water-exposed surfaces is discussed, i.e. the particle mobilization by drag force in oil phase is ignored.

Volume of exposed particle to low salinity water is function of water saturation; thus, Eq. (3) can be rewritten as

$$\sigma = \sigma_{cr}(\varepsilon, S) \tag{6}$$

In reservoir scale, the particle free run length (the distance that particle travels before being strained) is greatly smaller than the reservoir size. So, it is assumed that the released fines are captured instantly by porous media, leading to instant permeability reduction in water swept zones. The initial concentration of in-situ particles, σ_{a0} is assumed to be equal to maximum particle concentration for initial reservoir salt concentration, $\sigma_{a0} = \sigma_{a0}(\gamma_i)$ which can be determined using Eqs. (1)–(3).

Modifications are required to the standard two-phase flow system of equations to describe the flow of brine within the porous medium with fines release and capture. This system of equations for twophase flow with fines migration in large scale includes:

- volumetric balance equation for incompressible flux oil and water,
- volumetric balance for incompressible water,
- mass balance equation for attached and strained particles,
- maximum concentration of attached particles as a function of water flow velocity, salinity and saturation,
- advective mass transfer of salt in porous space with fines, and
 and modified Darcy's law for two-phase flow with strained
- particles.

$$\nabla(U) = 0 \tag{7}$$

$$\phi \frac{\partial S}{\partial t} + U \nabla f(S, \sigma_s) = 0 \tag{8}$$

$$f(S,\sigma_s(\varepsilon,S)) = \left[1 + \frac{k_{ro}(S)\mu_w(1+\beta\sigma_s(\varepsilon,S))}{k_{rw}(S)\mu_o}\right]^{-1}$$
(9)

$$\sigma_s(\varepsilon, S) = \sigma_{a0} - \sigma_a(\varepsilon, S) \tag{10}$$

$$\frac{\partial}{\partial t} [\phi \gamma] + \vec{\nabla} \left(\gamma \vec{U} \right) = 0 \tag{11}$$

$$U = -k \left[\frac{k_{rw}(S)}{\mu_w (1 + \beta \sigma_s(\varepsilon, S))} + \frac{k_{ro}(S)}{\mu_o} \right] \nabla p \tag{12}$$

The initial and boundary conditions are:

$$IC: t = 0: S = S_{wi}, \quad \gamma = \gamma_i, \quad \sigma_a = \sigma_{a0}, \quad \sigma_s = 0$$
(13)

BC:
$$r = r_w$$
: $f(1 - S_{or}, 0) = 1$, $\gamma = \gamma^0$ (14)

where γ_i , and γ^0 are salt concentrations of initial reservoir water and injected water, respectively.

5. Simulation of two-phase flow with fines migration using polymer model

In large scale approximation, the system of equation for polymer flooding and that for two-phase flow with fines migration are mathematically equivalent (Zeinijahromi et al., 2013). This equivalency is utilized to map system of equation for two-phase flow with fines migration during low salinity water injection on polymer flooding model. Eq. (15) describes the modified Darcy's law for polymer solution flow in porous media (Lake, 1989; Bedrikovetsky, 1993).

$$U = -\left[\frac{k_{rw}(S)\mu_o}{\mu_w(c_p)R_k(c_a)} + k_{ro}(S)\right]\nabla p \tag{15}$$

where R_k denotes the aqueous phase permeability reduction factor as a result of polymer adsorption on rock surface.

System of Eqs. (16)–(20) is introduced in order to map the system of equations for fines-assisted-water flood on the polymer flood, in large scale approximation. This provides the possibility of applying commercial polymer flood simulators to model low salinity water injection with induced formation damage.

$$R_k(c_a) = 1 + (\text{RRF} - 1) \frac{c_a(c_p)}{c_a(c_p^0)}$$
(16)

Here c_p and c_a are polymer concentrations in the aqueous phase and polymer adsorption concentration respectively. RRF is the residual resistance factor for the rock type. This quantity is greater than or equal to 1 and represents the decrease in the rock permeability to the aqueous phase when the maximum amount of polymer has been adsorbed (Schlumberger, 2013).

Polymer concentration (c_p) in the aqueous phase can be related to salt concentration (γ) during low salinity water flooding by

$$C_p = \frac{C_p^0}{\gamma_i - \gamma^0} (\gamma_i - \gamma) \tag{17}$$

where c_p^0 is the concentration of polymer at the injection well.

Mapping low salinity water flood equations on polymer flood equations yields the following expression for polymer adsorption concentration.

$$c_a(c_p) = \frac{\delta c_p^0 [\sigma_{a0} - \sigma_a(\gamma)]}{\gamma_i - \gamma^0}$$
(18)

 δ «1 is a small parameter; thus, the effect polymer adsorption on polymer concentration would be negligible.



Fig. 3. Maximum retention function.



Fig. 4. The simulated reservoir with edge-water drive.

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Fig. 5. Effects of fresh water bank injection on the sweep efficiency and residual oil at the abandonment time moment: (a) normal pressure depletion and (b) oil production with LSW bank injection.



Fig. 6. Field permeability alteration after LSW bank injection: creation of low permeable barrier.

Eq. (19) can be used to calculate maximum amount of permeability damage as a result of fines migration and capture.

$$RRF = 1 + \beta \left[\sigma_{a0} - \sigma_a(\gamma^0) \right]$$
(19)

Injection of low salinity water does not change the viscosity of the aqueous phase thus it is assumed to be independent of polymer concentration in the solution.

$$\mu_w(c_p) = \mu_w(0) \tag{20}$$

For detailed derivation of mapping low salinity water flood with fines migration on polymer flood system, see Zeinijahromi et al. (2013)

6. Results and discussions

A comparative study of production from an edge-water drive reservoir was performed using the black-oil model Eclipse 100 (Schlumberger, 2013). The reservoir has a dome shape and is connected to an active aquifer from the reservoir edges (Fig. 4). Initially, the reservoir contains 52 MM barrels of oil with initial water saturation of 20%. Nine production wells (P_1 – P_9) were drilled and are perforated through the entire thickness of the reservoir. Limits are set for the wells' water cut and field production rate. A well with water cut exceeding 95% is shut down and the operation ends when field reached its economic limit. Let us discuss first a homogenous reservoir with permeability of 300 mD.

Two water-drive production scenarios are modeled. All parameters are kept constant except in the improved recovery scenario a small volume of low salinity water is injected into the abounded wells to create a low permeable barrier against encroaching water. Similar production scenarios are also modeled using SPE9 reservoir heterogeneity.

For normal pressure depletion scenario, the production wells are closed after their produce water cut reached 95%; while for LSW injection case the watered-up wells (producing more than 95% water) are altered into injectors and 5000 STB/day of LSW are injected for two weeks before well abandonment. Fig. 5 shows oil saturation distribution after field abandonment. One can clearly see that the residual oil volume at field abandonment moment is greater for normal depletion (Fig. 5a), than that for LSW injection (Fig. 5b). During reservoir depletion the water from edge-aquifer overruns reservoir oil and yields in premature water production in structurally low wells. Water tongue continues to move towards the structurally high wells and leaves behind a significant volume of residual oil (Fig. 5a). While, injection of a small volume of LSW water into the structurally low wells creates a low permeable barrier zone that decelerate water tongues. This leads in prolongation of production life of wells that located higher in the structure and decrease the volume of trapped residual oil (Fig. 5b). The size of low permeability barrier that is needed to slow down the edgewater encroachment is small if compared to the reservoir size meaning that a small volume of LSW is required for injection (Fig. 6).

Fig. 7 shows the recovery factor for the homogenous reservoir model during normal depletion and LSW injection scenarios. Creating low permeability barrier with injection of a small volume of LSW yielded in prolongation of the reservoir life for 10 years



Fig. 7. Recovery factor vs time (years) for homogeneous reservoir case and moments of LSW injection in abounded wells.



Fig. 8. Cumulative water production (STB) vs time (years) for homogeneous reservoir.

and consequently improvement of ultimate recovery by \sim 5%. The created low permeable barrier has also caused reduction of cumulative water production (Fig. 8) if compared with that for normal depletion meaning that the injection LSW does not impose extra water production in the other producers.

Similar results are observed for the reservoir heterogeneity model SPE9. The volume of trapped oil has decreased with injection of into abounded wells (Fig. 9). Creation of low permeable barrier with induced formation damage method results in $\sim 4\%$ incremental recoveries by prolonging the reservoir production life by 30 years (Fig. 10). The cumulative water production for both production scenarios is identical before closing the first watered-up well (Fig. 11). Thereafter, formation of a low permeable barrier around the watered-up wells has resulted in a significant decrease in cumulative water production.

The results of reservoir simulation imply that creation of a low permeable barrier with injection small volume of LSW against the encroaching aquifer water can result in improved ultimate recover and reduction of total produced water. However, several restrictive assumptions have been made in order to model the induced formation damage method by polymer option of conventional numerical simulator. Hence, the results of the modeling study are indicative only. More realistic estimates of the reservoir behavior



Fig. 10. Recovery factor vs time (years) for SPE9 heterogeneity case and moments of LSW injection in abounded wells.



Fig. 9. Effects of LSW bank injection on the sweep efficiency and residual oil at the moment of the field abandonment (heterogeneous reservoir): (a) normal pressure depletion and (b) With LSW injection.



Fig. 11. Cumulative water production (STB) vs time (years) for SPE heterogeneity case.

and the efficiency of the LSW injection method require implementation of the saturation-dependent maximum retention function into the numerical reservoir simulator. It must be noted that this method of declaration encroaching edge-water is only applicable if the target reservoir contains in-situ movable fines.

7. Conclusions

The paper proposes applying short-term low salinity water injection into watered-up producers to create a low permeable barrier that can reduce water encroachment from the adjacent edge aquifer. Three-dimensional reservoir simulation of the LSW barrier technique results in the following conclusions:

Creation of a low permeable barrier with induced formation damage results in deceleration of water encroachment from edge aquifer and improves the ultimate recovery by \sim 3–5%. The incremental recovery is a result of delaying water breakthrough in updip producers and the consequent extended field production life.

The reduced water encroachment with injection of a small volume of LSW into watered-up well yields in decrease of residual oil volume trapped behind the encroaching water front.

The LWS blocking technique shows higher incremental oil recovery in highly heterogeneous reservoirs.

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