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Efficient Simulation for Low-Salinity Waterflooding in Porous and Fractured Reservoirs

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Abstract

Low-salinity brine injection has emerged as a promising, cost-effective improved oil recovery (IOR) method for waterflooding reservoirs. Laboratory tests and field applications show that low-salinity waterflooding could lead to significant reduction of residual oil saturation. There has been a growing interest with an increasing number of low-salinity waterflooding studies. However, there are few quantitative studies on flow and transport behavior of low-salinity IOR processes. This paper presents a general mathematic model (1) to incorporate known IOR mechanisms and (2) to quantify low-salinity waterflooding processes. In our mathematical conceptual model, salt is treated as an additional "component" to the aqueous phase, based on the following physical considerations: salt is transported only within the aqueous phase by advection and diffusion, and also subject to adsorption onto rock solids; relative permeability, capillary pressure, and residual oil saturation depend on salinity. Interaction of salt between mobile and immobile water zones is handled rigorously using a multi-domain approach. Fractured rock is handled using the multiple-continuum model or a discrete-fracture modeling approach. The conceptual model is implemented into a general-purpose reservoir simulator for modeling low-salinity IOR processes, using unstructured, regular, and irregular grids, applicable to 1-D, 2-D, and 3-D simulation of low-salinity water injection into porous media and fractured reservoirs. As demonstrated, the model provides a general capability for quantitative evaluation of low-salinity waterflooding in site-specific investigations.

Introduction

Waterflooding has been widely used as a secondary method to improve oil recovery for most oil reservoirs. Apart from formation damage, water floods are traditionally designed without considering the composition of the injected brine. However recent laboratory coreflood studies and field tests have showed that low-salinity waterflooding could result in a substantial oil recovery increase (2-40%) over traditional water flooding in many cases, depending on the reservoir formation minerals and brine composition (McGuire, et al, 2005, Lager, et al, 2008). The possible mechanisms for low-salinity waterflooding to improve oil recovery could be attributed to: (1) the wettability change towards water wet as a result of clay migration (Tang and Morrow, 1999); (2) the pH increase as a result of CaCO₃ dissolution, which increase oil recovery by several mechanisms including wettability alteration, generation of surfactants, and reduction in IFT (McGuire, et al, 2005), In general, the oil recovery improvement during low-salinity water flooding is recognized to depend on MIE, clay content, formation water composition (Ca²⁺, Mg²⁺), and oil composition.

In the petroleum industry, there has been a growing interest with an increasing number in low-salinity waterflooding studies. However, most of the work has focused on the extent of low-salinity water effect on improved oil recovery and the mechanisms of wettability alteration. In comparison, there are few quantitative studies on flow and transport behavior of low-salinity IOR processes. Jerauld et al (2006) modeled low-salinity waterflooding as a secondary and tertiary recovery processes in one dimensional model using salinity dependent oil/water relative permeability functions, resulting from wettability. Tripathi et al (2008) studied the flow instability associated with wettability alteration using a Buckley-Leveret type, analytical model in one dimension.

In this paper, we present a general numerical model for low-salinity water flooding in multidimensional, porous or fractured reservoirs. The model formulation incorporates known IOR mechanisms by low-salinity flooding for simulating low-salinity waterflooding processes. Two models, one homogenous model and one fracture model, were run to demonstrate the use of the proposed modeling approach in simulation of low-salinity water flooding.

(6)

Governing Equations

Let us consider a multiphase, isothermal system, composed of three phases and four mass components: oil, gas, water, and a salt (NaCl). Although each the three phases consist of several components, they are here treated as a single "pseudocomponent" with averaged properties of the fluid, and the salt is contained and transported only in the aqueous phase. The two liquid components, water and oil, are assumed to be present only in their associated phases. The gas exists in the gas phase and is also dissolved in the oil phase. Each phase flows in response to pressure, gravitational and capillary forces according to the multiphase extension of Darcy's law, including the effects of relative permeability and capillary pressures. Transport of the salt component occurs by advection and diffusion processes, in addition to adsorption on rock solids.

In an isothermal system containing four mass components, four mass balance equations are needed to fully describe the system. The mass balance equations for phase β (β = g for gas, =w for water, and = o for oil) and the salt are written in an arbitrary flow region as follows:

For gas,

$$\frac{\partial}{\partial t} \left\{ \phi \left(\mathbf{S}_{\mathbf{o}} \overline{\rho}_{\mathbf{dg}} + \mathbf{S}_{\mathbf{g}} \rho_{\mathbf{g}} \right) \right\} = -\nabla \bullet \left(\overline{\rho}_{\mathbf{dg}} \overline{\mathbf{V}}_{\mathbf{o}} + \rho_{\mathbf{g}} \overline{\mathbf{V}}_{\mathbf{g}} \right) + q_{\mathbf{g}}$$
(1)

For water,

$$\frac{\partial}{\partial t} \left\{ \phi \mathbf{S}_{w} \mathbf{X}_{w} \boldsymbol{\rho}_{w} \right\} = -\nabla \bullet \left(\mathbf{X}_{w} \boldsymbol{\rho}_{w} \, \vec{\mathbf{V}}_{w} \right) + \mathbf{q}_{w}$$
⁽²⁾

For oil,

$$\frac{\partial}{\partial t} \left(\phi \mathbf{S}_{o} \,\overline{\boldsymbol{\rho}}_{o} \right) = -\nabla \bullet \left(\overline{\boldsymbol{\rho}}_{o} \,\overline{\mathbf{V}}_{o} \right) + \mathbf{q}_{o} \tag{3}$$

For the salt component,

$$\frac{\partial}{\partial t} \left\{ \phi \mathbf{S}_{w} \mathbf{X}_{c} \boldsymbol{\rho}_{w} + (1 - \phi) \boldsymbol{\rho}_{R} \boldsymbol{\rho}_{w} \mathbf{X}_{c} \mathbf{K}_{d} \right\} =$$

$$- \nabla \bullet \left(\mathbf{X}_{c} \boldsymbol{\rho}_{w} \, \vec{\mathbf{V}}_{w} + \boldsymbol{\rho}_{w} \mathbf{S}_{w} \phi \, \tau \, \mathbf{D}_{m} \nabla \mathbf{X}_{c} \right) + \mathbf{q}_{c}$$

$$\tag{4}$$

The Darcy's velocity of phase β is defined as,

1_1_

 $S_{w} + S_{o} + S_{\sigma} = 1$

$$\vec{V}_{\beta} = -\frac{\kappa \kappa}{\mu_{\beta}} \left(\nabla P_{\beta} - \rho_{\beta} g \nabla d \right)$$
⁽⁵⁾

In the equations above, ρ_{β} is the density of phase β at reservoir conditions; $\overline{\rho}_{o}$ is the density of oil, excluding dissolved gas, at reservoir conditions; $\overline{\rho}_{dg}$ is the density of dissolved gas (dg) in oil phase at reservoir conditions; ϕ is the effective porosity of formation; μ_{β} is the viscosity of phase β ; S_{β} is the saturation of phase β ; P_{β} is the pressure of phase β ; X_{c} is the mass fraction of NaCl in water phase; X_{w} is the mass fraction of water component in water phase; ρ_{R} is the density of rock grains; K_{d} is the distribution coefficient of the salt component between the water phase and rock solids; D_{m} is the molecular diffusion coefficient of NaCl in the water phase in formation; τ is the tortuosity of porous media of formation rock; q_{c} is the sink/source term of NaCl unit volume of formation; q_{β} is the sink/source term of component β per unit volume of formation; q_{c} is the sink/source term of salt per unit volume of formation; g is gravitational acceleration; k is absolute/intrinsic permeability of formation; $k_{r\beta}$ is relative permeability to phase β ; and d is depth from a reference surface.

Constitutive Relations: The governing Equations (1)-(4) of mass conservation for three phases and NaCl component need to be supplemented with constitutive equations, which express all the parameters as functions of a set of primary thermodynamic variables of interest. The following relationships will be used to complete the statement of describing multiple phase flow of gas, water and oil, and NaCl component transport through porous media. In addition to the four governing equations of (1)-(4), there are two supplementary equations given by

and

$$X_{w} + X_{c} = 1 \tag{7}$$

Capillary Pressure: The capillary pressures are needed to relate pressures between the phases. For many subsurface rocks in reservoir conditions, the wettability is ordered as (1) aqueous (or oil) phase, (2) oil phase (or water), and (3) gas phase. Then, the oil phase pressure is related to the gas phase pressure by

$$\mathbf{P}_{\mathrm{o}} = \mathbf{P}_{\mathrm{g}} - \mathbf{P}_{\mathrm{cgo}} \left(\mathbf{S}_{\mathrm{w}}, \mathbf{S}_{\mathrm{o}} \right)$$
(8)

where P_{cgo} is the gas-oil capillary pressure in a three-phase system, which is a function of two saturations of water and oil phases, respectively. The oil-water capillary pressure, P_{cow} , in a three-phase system, is defined as,

$$\mathbf{P}_{o} - \mathbf{P}_{w} = \mathbf{P}_{cow}(\mathbf{S}_{w}, \mathbf{S}_{o}, \mathbf{X}_{c})$$
(9)

Note that in Equation (9), the capillary pressure between oil and water phase includes the effect of salt mass fraction (or concentration) in the aqueous phase, which is a main mechanism for low-salinity waterflooding to increase recovery efficiency by lowing or altering the oil-water capillary force. In case that there is no such capillary curve between oil-water phases under low-salinity waterflooding, we may use introduce the following form using the J-function:

$$P_{cow} = \frac{\sigma(X_c)\cos\theta(X_c)}{(\sigma\cos\theta)^0} P_{cow}^0(S_w, S_o)$$
(10)

where σ is the interface tension between oil-water phases; and subscript 0 denotes the *in-situ* condition of reservoir brine, *Relative Permeability:* The relative permeabilities are assumed to be a function of fluid saturations and salt concentration

when simulating low-salinity displacement processes. The relative permeability to water phase is described,

$$\mathbf{k}_{\mathrm{rw}} = \mathbf{k}_{\mathrm{rw}} \left(\mathbf{S}_{\mathrm{w}}, \mathbf{X}_{\mathrm{c}} \right)$$
(11)

to oil phase,

$$\mathbf{k}_{\rm ro} = \mathbf{k}_{\rm ro} \left(\mathbf{S}_{\rm w}, \mathbf{S}_{\rm g}, \mathbf{X}_{\rm c} \right) \tag{12}$$

and to gas phase,

$$k_{rg} = k_{rg} (S_g, X_c)$$
(13)

When there are no three-phase relative permeability data available, the oil relative permeability is determined using the Stone method II (Aziz and Settari, 1979),

$$k_{ro} = k_{ro}^{*wo} \left[\binom{k_{ro}^{wo}}{k_{ro}^{*wo}} + k_{rw}}{k_{ro}^{wo}} + k_{rg} - (k_{rw} + k_{rg}) \right]$$
(14)

where k_{ro}^{*wo} is the relative permeability value to oil at residual water saturation in the water-oil, two-phase system; k_{ro}^{wo} is the relative permeability to oil in the water-oil, two-phase system; and k_{ro}^{og} is the relative permeability to oil in the oil-gas, two-phase system. With Equation (14) of the Stone II function, we can evaluate three-phase relative permeability using two sets of two-phase flow relative permeabilities determined from water-oil and oil-gas systems, respectively.

PVT Data: The densities of oil, gas and water under reservoir conditions can be treated as functions of formation volume factors in general as. For oil,

$$\rho_{o} = \frac{1}{B_{o}} \left[\left(\rho_{o} \right)_{STC} + R_{s} \left(\rho_{g} \right)_{STC} \right]$$

$$= \overline{\rho}_{o} + \overline{\rho}_{dg}$$
(15)

For water

$$\rho_{\rm w} = \frac{\left[\rho_{\rm w}({\rm X}_{\rm c})\right]_{\rm STC}}{{\rm B}_{\rm w}} \tag{16}$$

and for gas

$$\rho_{g} = \frac{\left(\rho_{g}\right)_{STC}}{B_{g}} \tag{17}$$

where \mathbf{B}_{β} is formation volume factor for phase β ; $(\rho_{\beta})_{\text{STC}}$ is density of phase β at standard condition (or storage tank condition); \mathbf{R}_{\circ} is solution gas-oil ratio. Note that

$$\overline{\rho}_{o} = \frac{\left(\rho_{o}\right)_{STC}}{B_{o}}$$
(18)

and

$$\overline{\rho}_{dg} = \frac{R_s \left(\rho_g\right)_{STC}}{B_o}$$
(19)

In general, formation volume factors and solution gas-oil ratios are functions of reservoir pressures and the bubble point as in a three-phase black oil reservoir. The following functional correlations are used,

$$\mathbf{B}_{o} = \mathbf{B}_{o} \left(\mathbf{P}_{o}, \ \mathbf{P}_{b} \right) \tag{20}$$

$$_{g} = B_{g}(P_{g})$$
⁽²¹⁾

$$_{w} = \frac{B_{w}^{o}}{1 + C_{w} (P_{w} - P_{b}^{o})}$$
(22)

and

$$\mathbf{R}_{s} = \mathbf{R}_{s} \left(\mathbf{P}_{o}, \, \mathbf{P}_{b} \right) \tag{23}$$

where P_b is the bubble point (pressure) of the reservoir; B_w^o is the formation volume factor of water at initial bubble point

pressure, P_b^o ; and C_w is compressibility of water phase.

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В

Gas and oil viscosities are treated functions of phase pressure only,

$$\mu_{\beta} = \mu_{\beta} (\mathbf{P}_{\beta}) \tag{24}$$

Water or aqueous phase viscosity is handled as a function of salt concentration as,

$$\mu_{\rm w} = \mu_{\rm w} \big(X_{\rm c} \big) \tag{25}$$

Numerical Formulation

The methodology to simulate multiphase flow and salt transport follows common reservoir simulation approaches, consisting of the three steps: (1) spatial discretization of mass conservation equations, (2) time discretization; and (3) iterative approaches to solve the resulting nonlinear, discrete algebraic equations. A mass- conserving discretization scheme, based on a finite or integral finite-difference method, is used and is discussed here.

Discretized Equations: The numerical discretization technique used in the paper is the "integral finite difference" method (Narasimhan and Witherspoon, 1976; Pruess, 1991; Pruess et al. 1999). The mass balance equations for oil, gas, water, and salt are expressed in terms of a set of discrete integral finite difference equations. These discrete equations are then solved fully implicitly to provide stability and large time step size. In the numerical approach, thermodynamic properties of fluids and rock are represented by averages over explicitly defined finite subdomains or grid blocks, while fluxes of mass across surface segments between connected grid blocks are evaluated by finite difference approximations (Figure 1). The discretized, non-linear, finite difference mass-balance equations are then solved simultaneously, using the Newton/Raphson iteration procedure.

The mass balance Equations (1)-(4) are discretized in space using the integral finite difference scheme. The time discretization is carried out with a backward, first-order finite difference method. Then the discrete non-linear equations of gridblock (or element) i (i =1, 2, 3, ..., N; N being the total number of elements in the grid) are written in residual forms as follows:

For gas,

$$R_{i}^{g,n+1} = \left\{ \! \left[\! \varphi S_{o} \overline{\rho}_{dg} + \varphi S_{g} \rho_{g} \right]_{i}^{n+1} - \left[\! \varphi S_{o} \overline{\rho}_{dg} + \varphi S_{g} \rho_{g} \right]_{i}^{n} \right\} \frac{V_{i}}{\Delta t} - \sum_{j \in \eta_{i}} \left(\! \overline{\rho}_{dg} \lambda_{o} \right)_{ij+1/2}^{n+1} \gamma_{ij} \! \left[\! \psi_{oj}^{n+1} - \psi_{oi}^{n+1} \right] \! - \sum_{j \in \eta_{i}} \left(\! \rho_{g} \lambda_{g} \right)_{ij+1/2}^{n+1} \gamma_{ij} \! \left[\! \psi_{gj}^{n+1} - \psi_{gi}^{n+1} \right] \! - Q_{gi}^{n+1}$$
(26)

- -

For water

$$R_{i}^{w,n+1} = \left\{ \left[\phi S_{\beta} X_{w} \rho_{w} \right]_{i}^{n+1} - \left[\phi S_{w} X_{w} \rho_{w} \right]_{i}^{n} \right\} \frac{V_{i}}{\Delta t} - \sum_{j \in \eta_{i}} \left(\rho_{w} X_{w} \lambda_{w} \right)_{ij+1/2}^{n+1} \gamma_{ij} \left[\psi_{wj}^{n+1} - \psi_{wi}^{n+1} \right] - Q_{wi}^{n+1}$$
(27)

for oil,

$$\mathbf{R}_{i}^{o,n+1} = \left\{ \left[\phi \mathbf{S}_{o} \overline{\rho}_{o} \right]_{i}^{n+1} - \left[\phi \mathbf{S}_{o} \overline{\rho}_{o} \right]_{i}^{n} \right\} \frac{\mathbf{V}_{i}}{\Delta t} - \sum_{j \in \eta_{i}} \left(\overline{\rho}_{o} \lambda_{o} \right)_{ij+1/2}^{n+1} \gamma_{ij} \left[\psi_{oj}^{n+1} - \psi_{oi}^{n+1} \right] - \mathbf{Q}_{oi}^{n+1}$$

$$\tag{28}$$

for salt

$$R_{i}^{c,n+1} = \left\{ \left[\phi S_{w} X_{c} \rho_{w} + (1-\phi) \rho_{R} \rho_{w} X_{c} K_{d} \right]_{i}^{n+1} - \left[\phi S_{w} X_{c} \rho_{w} + (1-\phi) \rho_{R} \rho_{w} X_{c} K_{d} \right]_{i}^{n} \right\} \frac{V_{i}}{\Delta t} - \sum_{j \in \eta_{i}} \left(\rho_{w} X_{c} \lambda_{w} \right)_{ij+1/2}^{n+1} \gamma_{ij} \left[\psi_{wj}^{n+1} - \psi_{wi}^{n+1} \right] - \sum_{j \in \eta_{i}} \left(\rho_{w} S_{w} \right)_{ij+1/2}^{n+1} \gamma_{ij}^{D} \left[X_{cj}^{n+1} - X_{ci}^{n+1} \right] - Q_{ci}^{n+1}$$
(29)

where n denotes the previous time level; n+1 is for the current time level to be solved; V_i is the volume of element i; Δt is time step size; η_i contains the set of neighbor elements (j) or nodes of element i to which element i is directly connected; subscript ij+1/2 denotes a proper averaging at the interface between two elements i and j, with the mobility of phase β , the mobility,

$$\lambda_{\beta} = \frac{k_{r\beta}}{\mu_{\beta}} \tag{30}$$

and the transmissivity of flow terms is defined as

$$\gamma_{ij} = \frac{A_{ij}k_{ij+1/2}}{D_i + D_j}$$
(31)

and the transmissivity of diffusion terms is defined as

$$\gamma_{ij}^{\mathrm{D}} = \frac{A_{ij} (\phi \tau D_{\mathrm{m}})_{ij+1/2}}{D_{i} + D_{j}}$$
(32)

and the potential term,

$$\psi_{\beta i}^{n+1} = P_{\beta i}^{n+1} - \rho_{\beta, i j + 1/2}^{n+1} g d_i$$
(33)

In Equations (31)-(33), A_{ij} is the common interface area between connected elements i and j (Figure 1); D_i is the distance from the center of element i to the interface between elements i and j; D_j is the distance from the center of element j to the interface between elements i and j; $k_{ij+1/2}$ is the averaged absolute permeability along the connection between elements i and j; and d_i is the depth to the center of element i. The sink/source term for element i in the residual equations, Q_{oi} is defined as

$$\mathbf{Q}_{\omega i}^{n+1} = \mathbf{q}_{\omega i}^{n+1} \mathbf{V}_{i} \tag{34}$$

for $\omega = g$, w, o or c for gas, water, oil or salt, respectively.

The upstream weighting scheme is used for averaging relative permeability of the mobility term (30) and the harmonic weighting is used for absolute permeability in (31).

Numerical Solution Technique: The Newton/Raphson iteration is used to solve Equations (26) to (29) of a flow system, representing $4 \times N$ coupled non-linear equations, which include four equations at each element for four mass balance equations of gas, water, oil and salt, respectively. Four primary variables (x_1, x_2, x_3, x_4) are selected for each element, which are oil pressure, oil saturation, saturation pressure (or gas saturation), and mass fraction of salt, as shown in Table 1. The selection of primary variables are similar to that of a black-oil reservoir simulator. An automatic variable switching scheme is used to handle the transition of free gas appearing and disappearing during simulation studies of oil production with oil, gas and water three-phase flow conditions.

As indicated by Table 1, three of the four primary variables are fixed, and the third variable depends on the phase condition at a node. If there is no free gas, a node is said to be undersaturated or above the bubble point and saturation pressure, P_s , is used as the third primary variable. When free gas is present, a node is said to be saturated or below the bubble point, then gas saturation, S_g , is the third primary variable. This variable switching scheme is very rigorous and efficient in handling variable bubble-point problems, which are often encountered in reservoir simulations (Thomas and Lumpkin, 1976). Numerical experiment shows that choice of different primary variables makes a difference in numerical performance during nonlinear iterations of solving a three-phase flow problem, and the best combination is to select the mixed formulation, as shown in Table 1, for handling phase transitions under different capillary/phase conditions.

In terms of the four primary variables, the Newton/Raphson scheme gives rise to,

$$R_{i}^{\omega,n+1}(x_{k,p+1}) = R_{i}^{\omega,n+1}(x_{k,p}) + \sum_{k} \frac{\partial R_{i}^{\omega,n+1}(x_{k,p})}{\partial x_{k}} [x_{k,p+1} - x_{k,p}] = 0$$
(35)

for $\omega = g$, w, o or c for gas, water, oil or salt, respectively; where index k = 1, 2, 3, and 4 for primary variable 1, 2, 3, and 4, respectively; p is iteration level. Equation (35) can be written as,

$$\sum_{k} \frac{\partial R_{i}^{\omega,n+1}(x_{k,p})}{\partial x_{k}} \left(\delta x_{k,p+1} \right) = -R_{i}^{\omega,n+1}(x_{k,p}) \qquad \text{for } k=1, 2, 3 \text{ and } 4$$
(37)

for i =1, 2, 3, ..., N and with an increment of primary variables over the iteration,

(38)

$$\delta \mathbf{x}_{\mathbf{k},\mathbf{p}+1} = \mathbf{x}_{\mathbf{k},\mathbf{p}+1} - \mathbf{x}_{\mathbf{k},\mathbf{p}}$$

The Newton iteration process continues until the residuals $R_n^{k,n+1}$ or changes in the primary variables $\delta x_{m,p+1}$ over an

iteration are reduced below preset convergence tolerances. Numerical methods are used to construct the Jacobian matrix for Equation (37), as outlined in Forsyth et al. (1995). At each Newton iteration, Equation (37) represents a set of 4×N linear equations for 4×N unknowns of $\delta x_{k,p+1}$, with sparse unsymmetrical matrices, and are solved by a linear iterative equation solver.

Handling Initial and Boundary Conditions: A set of initial conditions is required to start a transient simulation, i.e., a complete set of primary variables need to be specified for every gridblock or node. A commonly used procedure for specifying initial conditions is based on gravity-capillary equilibrium calculation initially or the restart option for the following simulations, in which a complete set of initial conditions or primary unknowns is generated in a previous simulation, with proper boundary conditions described.

Using a block-centered grid, first-type or Dirichlet boundary conditions are treated with the "inactive cell" or "bigvolume" method, as normally used in the TOUGH2 code (Pruess, 1991). In this method, a constant pressure/saturation/concentration node is specified as an inactive cell or with a huge volume, while keeping all the other geometric properties of the mesh unchanged. For flux-type boundary conditions, or more general types of flux or mixed boundaries, such as multilayered wells, general procedures for handling such boundary conditions are implemented, as discussed in Wu et al. (1996; 2000).

Treatment of Fracture-Matrix Interaction: The mathematical and numerical formulations discussed above are applicable to both single-continuum and multicontinuum media using the generalized multicontinuum concept. The technique used in this paper for handling multiphase flow through fractured rock follows the dual-continuum methodology (warren and Root, 1963; Pruess and Narasimhan, 1985; Wu and Pruess, 1988). This method treats fracture and matrix flow and interactions using a multicontinuum numerical approach, including the double- or multiporosity method, the dual-permeability method, and the more general MINC method. Using the dual-continuum concept, Equations (1) to (4) or (26) to (29) can be used to describe multiphase flow both in fractures and inside matrix blocks, as well as fracture-matrix interaction, or flow in discrete fractures. However, special attention needs to be paid to treating fracture-matrix flow or transport.

When handling flow and transport through a fractured rock using the generalized numerical formation of this paper, fractured media (including explicit fracture, dual, or multiple continuum models) can be considered as special cases of unstructured grids (Pruess, 1991). Then, a large portion of the work of modeling flow in fractured rock consists of generating a mesh that represents both the fracture system and the matrix system under consideration. Several fracture and matrix subgridding schemes exist for designing different meshes for different fracture-matrix conceptual models (Pruess and Narasimhan, 1985; Pruess, 1983). Once a proper grid of a fracture-matrix system is generated, fracture and matrix blocks are identified to represent fracture and matrix domains, separately. Formally they are treated identically for the solution in the model simulation. However, physically consistent fracture and matrix properties, parameter weighting schemes, and modeling conditions must be appropriately specified for both fracture and matrix systems.

Handling immobile water zones: As an application example of the generalized multicontinuum concept, discussed above, immobile or residual water zones of *in-situ* brine within porous pores can be handled as a separate domain containing immobile water only, such as "dead" pores, as one additional continuum with zero permeability. The salt within the immobile zones will interact with mobile water zones by diffusion only. This diffusion process is described by the same governing equations or numerical formulation, discussed above, as a special case of no flow and diffusion processes only.

Application

To demonstrate the usefulness of the proposed modeling approach in simulation of low-salinity water flooding, we present three application examples. Note that the proposed model formulation has been implemented and tested in the generalpurpose reservoir simulator MSFLOW (Wu, 2000), which is used in the following application examples. In the first example, we attempt to match published analytical solution for single-phase water and solute transport in a one-dimensional flow domain. In the second example, we simulate oil-water two-phase displacement with waterflooding at different salinity to examine the displacement efficiency in a porous medium. The third example is to look at displacement through a fractured rock.

One-dimensional transport problem: This problem is designed to examine the accuracy of the model formation and numerical implementation in simulating salt transport in the aqueous phase with effective molecular diffusion and is similar to the one used by Wu et al. (1996). The problem considers one-dimensional transport of a chemical component in a homogeneous water-saturated porous medium 10 meters long. The flow field is steady-state with 0.1 m/day velocity. A chemical component is introduced at the inlet (x=0) with a constant concentration, and transport starts at t=0 by advection and diffusion. An analytical solution for this problem is provided by Javandel et al. (1984), and it is used here to verify the numerical solution.

The numerical solution of this problem is accomplished by specifying both inlet and outlet boundary elements with constant pressures, which give rise to a steady state flow field of 0.1 m/day pore velocity. In the numerical simulation, a one-

dimensional, uniform linear grid of 1,000 elements was generated for the 10-meter domain. In order to eliminate effects of three-phase flow, only single-phase water is specified. The properties used in the comparison are: porosity $\phi = 1$, tortuosity $\tau = 1$, and effective molecular diffusion coefficient $D_m = 1.157 \times 10^{-7} \text{ m}^2/\text{s}$. The initial and boundary conditions are: initially there is no salt existing in the system; $X_{salt} = 1.0 \times 10^{-5}$ at the inlet boundary (x = 0); and $X_{salt} = 0$ at the outlet boundary at all times.

A comparison of the salt concentrations along the rock column from the numerical and analytical solution is shown in Figure 2 for t=10 and 20 days, respectively. The figure indicates that the simulated concentration profiles are in excellent agreement with the analytical solution, and also shown are comparisons with results from another numerical code (T2R3D) (Wu et al., 1996). Good agreement between the numerical and analytical solutions provides some verification of the numerical formation and its implementation.

Displacement problem in a porous medium: This example problem considers a one-dimensional immiscible displacement problem, in which oil in a one-dimensional linear rock column is displaced by water injected with the same salinity (or called high salinity) as well as low salinity. The flow domain is along a one-dimensional, horizontal, homogeneous, and isotropic porous medium of 10-meter long with a unit cross-sectional area. The system is initially saturated with oil and water with water at its residual saturation. Water with two different salinities is injected as a displacing fluid at the inlet to drive oil out of the porous medium domain. Then, we compare the recovery rates by two different salinity waterflooding. The one dimensional domain is represented by 100 uniform grid blocks of one dimension in the numerical model, with uniform mesh spacing ($\Delta x = 0.1$ m).

To account for effects of low salinity in the aqueous phase on relative permeability and capillary pressures, special functional forms of relative permeability and capillary pressure functions are used, as discussed below. For relative permeability curves in the oil-water two-phase system, the Brooks-Corey type of function (Honarpour et al., 1986) is used with slight modifications of (1) no change relative permeability to water phase and (2) increase in relative permeability to oil phase as salinity decreases as,

$$\mathbf{k}_{\mathrm{rw}} = \left(\overline{\mathbf{S}}_{\mathrm{w}}\right)^{2+\phi} \tag{39}$$

$$\mathbf{k}_{\rm ro} = \left(\overline{\mathbf{S}}_{\rm o}\right)^2 \left[1 - \left(\overline{\mathbf{S}}_{\rm w}\right)^{\rm o}\right] \tag{40}$$

where the two normalized fluid saturations are defined below, and φ is an exponential index.

$$\overline{\mathbf{S}}_{w} = \frac{\mathbf{S}_{w} - \mathbf{S}_{wr}}{1 - \mathbf{S}_{wr}} \tag{41}$$

$$\overline{\mathbf{S}}_{\mathrm{o}} = \frac{\mathbf{S}_{\mathrm{o}} - \mathbf{S}_{\mathrm{or}}(\mathbf{X}_{\mathrm{c}})}{1 - \mathbf{S}_{\mathrm{wr}}}$$
(42)

with Sor being residual oil saturation, a function of salinity in the aqueous phase.

The capillary pressure function from van Genuchten (1980) and Parker et al. (1987) is used for the oil-water system with modification of adding the cosine of contact angles of oil and water phases on rock surface to include effect of lower salinity in water,

$$P_{cow} = \left(\frac{\cos\theta}{(\cos\theta)^0}\right) \left(\frac{\rho_w g}{\alpha_{vG}}\right)^0 \left[\left(\overline{S}_w\right)^{-1/\gamma} - 1\right]^{1/\beta}$$
(43)

where α_{vG} , γ and β are parameters of the van Genuchten functions (van Genuchten, 1980) with $\gamma = 1 - 1/\beta$.

Furthermore, for this example problem, we assume that there exist a linear relationship between salt mass fraction and residual oil saturation (S_{or}) or contact angle (θ) as,

$$S_{or}(X_{c}) = S_{or1} + \frac{X_{c} - X_{c1}}{X_{c1} - X_{c2}} (S_{or1} - S_{or2})$$
(44)

where S_{or1} is the residual oil saturation (minimum residual oil saturation) at low salt mass fraction, X_{c1} , and S_{or2} is the residual oil saturation (maximum residual oil saturation) at high salt mass fraction, X_{c2} .

$$\theta(X_{c}) = \theta_{or1} + \frac{X_{c} - X_{c1}}{X_{c1} - X_{c2}} \left(\theta_{or1} - \theta_{or2}\right)$$
(45)

where θ_{or1} is the contact angle at low salt mass fraction, X_{c1} , and θ_{or2} is the contact angle at high salt mass fraction, X_{c2} .

The properties of rock and fluids, as well as the parameters with the modified relative permeability and capillary pressure functions of Equations (39)-(44), are given in Table 2. Note that for this horizontal displacement problem, effect of salinity on aqueous density and viscosity is ignored. The simulation results, in terms of injected pore volume and oil recovery rates are shown in Figures 3 and 4. Figure 3 presents a comparison for low-salinity waterflooding under zero capillary pressure

condition, showing a significant improvement in oil recovery rate by the low-salinity waterflooding. In this case, there are no capillary or wettability effects, and the improvement is due only to the improvement in lower residual oil saturation and in oil relative permeability curves. The simulation time was set to 270 day, and it took 500 time steps and 1,271 Newton iterations, and 3 seconds of CPU times to complete on a laptop PC.

Figure 4 shows the results and comparison when including all effects on residual oil saturation, oil relative permeability, and capillary pressure curves. In this case, in addition to the effects of decrease in residual oil saturation and increase in oil relative permeability values, the wettability changes to zero capillary pressure condition at the low salinity flooding, i.e., ($\theta = 0$ to $\theta = \pi/2$). As shown in Figure 4, there is also significant improvement in oil recovery in this case. The oil recovery rate at 5 PV for the low-salinity flooding is similar to the previous scenario at zero capillary pressure, because $\theta = \pi/2$ in this simulation.

Displacement problem in a double-porosity fractured medium: This problem is designed to look at the effect of low-salinity waterflooding in a fractured medium. This problem considers a low-salinity displacement process in a onedimensional, horizontal, and uniform, fractured reservoir. The formation domain is a 10-m long fractured rock column with a unit cross-sectional area, which is similar to that in the previous porous medium example. The fractured rock is conceptualized as a parallel-fracture model, consisting of one horizontal fracture plate (fracture spacing A = 1.0 and fracture porosity =0.1%), which is overlain and underlain by uniform layered matrix blocks of 0.5-meter thick. In numerical discretization, the one-dimensional grid, used in the previous example for the porous medium column, is used as the primary mesh to generate the double-porosity grid, by separating each grid block in the primary mesh into two blocks, one for fracture and the other for matrix, in the double-porosity grid. The only globally connecting meshes are fracture ones.

Fractures and matrix parameters used for the example are given in Table 3. Note that for this demonstration example, we keep capillary pressure curves for fractures and the matrix not to change with salinity, i.e., not including effects of salinity on capillary pressures in fractures and matrix systems. This is because of the lack in laboratory measured capillary pressure data for fractures and matrix systems under different salinities. Also, the capillary curves are among the most sensitive properties for matrix imbibition, a main mechanism for oil recovery from fractured reservoirs by waterflooding.

Figure 5 displays the model results for this case of low-salinity waterflooding through a fractured rock. A comparison of the oil recovery rates with high- and low-salinity indicates (1) much slower and lower recovery rate and (2) much smaller difference in improvement, when compared with the case for the displacement in porous media of the previous problem. This is primarily due to much larger contract in fracture and matrix permeabilities (1 Darcy vs. 1 milli-Darcy), which makes the improvement in effective fracture permeabilities relatively insignificant with lowering salinity. This small improvement by low-salinity waterflooding in fractured reservoirs, as shown in Figure 5, may or may not reflect the performance of low-salinity waterflooding in actual reservoir applications, which indicates the low-salinity water flooding could not lead to satisfied improved oil recovery for fractured reservoirs if the effect of the low salinity water effect on capillary pressure is not considered.

Summary

In this paper, we present a mathematical model for modeling low-salinity waterflooding in porous or fractured reservoirs. In the model, salt is treated as an additional "component" to the aqueous phase in a gas, oil, and water three-phase flow system, and is transported only within the aqueous phase by advection and diffusion. In addition, salt is subject to adsorption onto rock solids. The main mechanisms of IOR by low-salinity water injection are described by incorporating salinity-dependent changes in relative permeability, capillary pressure, and residual oil saturation in the model formulation. Furthermore, the interaction of salt between mobile and immobile water zones and flow in fractured rock are handled using a general multiple-continuum approach modeling approach. The proposed mathematical model is implemented into and tested with a general-purpose reservoir simulator. The low-salinity waterflooding simulator uses unstructured, regular, and irregular grids, and is applicable to 1-D, 2-D, and 3-D simulation of low-salinity water injection into porous media and fractured reservoirs. As demonstrated, the model provides a general capability for quantitative evaluation of low-salinity waterflooding in site-specific investigations.

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	A	
Equations	Primary variable	Physical variable
Gas (26)	$x_1 = P_o$	Oil pressure
Water (27)	$\mathbf{x}_2 = \mathbf{S}_0$	Oil saturation
Oil (28)	$x_3 = P_s or$	Saturation pressure or
	$\mathbf{x}_3 = \mathbf{S}_g$	gas saturation
Salt (29)	$\mathbf{x}_4 = \mathbf{X}_c$	Mass fraction of salt

Table 1. Choice of the primary variables and associated equations.

Table 2 Parameters for displacement in one-dimensional porous medium column.

Parameter	Value	Unit
Porosity	$\phi = 0.30$	
Reference water density	$\rho_{\rm w} = 1,000$	kg/m ³
oil density	$\rho_o = 864$	kg/m ³
Water phase viscosity	$\mu_{\rm w} = 1.139 \times 10^{-3}$	Pa∙s
Oil viscosity	$\mu_0 = 4 \times 10^{-3}$	Pa∙s
Permeability	k = 1	Darcy
Salt diffusion coefficient	$D_m = 1 \times 10^{-10}$	m ² /s
Injection rate	q = 0.1	m ³ /d
Initial oil saturation	$S_0 = 0.8$	
Residual water saturation	$S_{wr} = 0.2$	
Low salinity mass fraction	X _c =0.001	
High or initial salinity mass fraction	X _c =0.01	
Residual oil saturation at X _c =0.001	$S_{or1} = 0.1$	
Residual oil saturation at X _c =0.01	$S_{or2} = 0.3$	
Contact angle at X _c =0.01	$\theta = 0.0$	
Contact angle at X _c =0.001	$\theta = \pi/2$	
Relative permeability exponential	$\phi = 1$	
van Genuchten α_{vG}	$\alpha_{vG} = 2 \times 10^{-2}$	Pa ⁻¹
van Genuchten β	β=0.5	

Table 3 Parameters for displacement in one-dimensional fractured rock column.

Parameter	Value	Unit
Porosity	$\phi = 0.30$	
Reference water density	$\rho_{\rm w} = 1,000$	kg/m ³
oil density	$\rho_{0} = 864$	kg/m ³
Water phase viscosity	$\mu_{\rm w} = 1.139 \times 10^{-3}$	Pa∙s
Oil viscosity	$\mu_0 = 4 \times 10^{-3}$	Pa●s
Permeability	k = 1	Darcy
Salt diffusion coefficient	$D_m = 1 \times 10^{-10}$	m ² /s
Injection rate	q = 0.1	m ³ /d
Initial oil saturation	$S_0 = 0.8$	
Residual water saturation	$S_{wr} = 0.2$	
Low salinity mass fraction	Xc=0.001	
High or initial salinity mass fraction	X _c =0.01	
Matrix residual oil saturation at X _c =0.001	$S_{or1, M} = 0.1$	
Matrix residual oil saturation at X _c =0.01	$S_{or2, M} = 0.3$	
Fracture residual oil saturation at Xc=0.001	$S_{or1, F} = 0.05$	
Fracture residual oil saturation at Xc=0.01	$S_{or2, F} = 0.1$	
Matrix relative permeability exponential	$\phi = 3$	
Fracture relative permeability exponential	$\phi = 1$	
Matrix van Genuchten α_{vG}	$\alpha_{\rm vG, M} = 2 \times 10^{-2}$	Pa ⁻¹
Matrix van Genuchten β	$\beta_M = 0.5$	
Fracture van Genuchten α_{vG}	$\alpha_{vG, F} = 1 \times 10^{-1}$	Pa ⁻¹
Fracture van Genuchten β	$\beta_{\rm F} = 0.5$	

Parameter	Value	Unit
Matrix porosity	$\phi_{\rm M}=0.30$	
fracture porosity	$\phi_F = 0.001$	
Reference water density	$\rho_{\rm w} = 1,000$	kg/m ³
oil density	$\rho_o = 864$	kg/m ³
Water phase viscosity	$\mu_{\rm w} = 1.139 \times 10^{-3}$	Pa●s
Oil viscosity	$\mu_0 = 4 \times 10^{-3}$	Pa∙s
Matrix permeability	$k_{M} = 1$	mD
Fracture permeability	$K_{\rm F} = 1$	D
Salt diffusion coefficient	$D_{\rm m} = 1 \times 10^{-10}$	m ² /s
Injection rate	q = 0.01	m ³ /d
Matrix initial oil saturation	$S_0 = 0.8$	
Fracture initial oil saturation	$S_0 = 0.99$	
Matrix residual water saturation	$S_{wr,M} = 0.2$	
Fracture residual water saturation	$S_{wr,F} = 0.01$	
Low salinity mass fraction	X _c =0.001	
High or initial salinity mass fraction	X _c =0.01	
Matrix residual oil saturation at X _c =0.001	$S_{or1, M} = 0.1$	
Matrix residual oil saturation at X _c =0.01	$S_{or2, M} = 0.3$	
Fracture residual oil saturation at X _c =0.001	$S_{or1, F} = 0.05$	
Fracture residual oil saturation at Xc=0.01	$S_{or2, F} = 0.1$	
Matrix relative permeability exponential	$\phi = 3$	
Fracture relative permeability exponential	$\phi = 1$	
Matrix van Genuchten α_{vG}	$\alpha_{\rm vG, M} = 2 \times 10^{-2}$	Pa ⁻¹
Matrix van Genuchten β	$\beta_{\rm M} = 0.5$	
Fracture van Genuchten α_{vG}	$\alpha_{\rm vG, F} = 1 \times 10^{-1}$	Pa ⁻¹
Fracture van Genuchten β	$\beta_{\rm F} = 0.5$	

Table 3 Parameters for the displacement problem in a fractured rock column.



Figure 1. Space discretization and flow-term evaluation in the integral finite difference method.



Figure 2. Comparison of model results with the analytical and other numerical code solutions.



Figure 3. Comparison of simulated recovery rates for low- and high-salinity waterflooding through one-dimensional rock column at zero capillary pressure condition.



Figure 4. Comparison of simulated recovery rates for low- and high-salinity waterflooding through one-dimensional rock column at salinity-dependent capillary pressure condition.



Figure 5. Comparison of simulated recovery rates for low- and high-salinity waterflooding through one-dimensional double-porosity fractured rock column at the same capillary pressure condition.