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MULTIPHASE FLOW OF WATER AND OIL IN HETEROGENEOUS RESERVOIR

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Abstract *This paper presents a study of oil production in an outcrop considered as an analogous subsurface reservoir. This outcrop (Barreiras do Boqueirão) is located in the northeast coast of Brazil. The analysis considers a multiphase porous medium, with water and oil as fluid phases. Oil production is stimulated by water flooding in the reservoir. The influence of flooding water temperature is also considered in the analysis (non isothermal conditions). In this case, the flooding process, besides displacing the oil toward the production well, will also result in temperature changes inside the formation, affecting directly the fluid properties of the displaced fluids as viscosity and density. According to the geological characterization, the formation is stratified with great permeability variations between the layers. This consideration increases the numerical solution complexity of flow and heat equations. The numerical tool used in this study is the Finite Element program CODE_BRIGHT, which solves in a coupled way the flow equations of water and oil and the internal energy balance (heat equation) for a multiphase porous medium, which in the particular case of this application is considered a rigid medium. By using reservoir engineering indicators, the impacts on oil production are analyzed when the formation heterogeneity and the influence of flooding water temperature are considered, showing the importance of this numerical tool in controlling fluid production.*

1 INTRODUCTION

Studying and modeling of sedimentary deposits outcrops as analogous of subsurface reservoirs is a fundamental tool on the comprehension and prediction of the behavior of a reservoir in real conditions. From the complete knowledge of depositional systems, its nature, geometry and petrophysical properties it's possible to predict and develop physical and mathematical models applicable to subsurface reservoirs, minimizing costs and optimizing hydrocarbon exploration.

In this context, this paper presents a study of multiphase flow of water and oil in nonisothermal conditions in the Barreiras do Boqueirão outcrop. This outcrop, located in the northeast coast of Brazil, is a turbiditic sequence considered as an analogous of subsurface reservoir[1].

One of the most common petroleum engineering problem in mature fields is the need of efficient techniques to increase oil production. Among the developed techniques that can be used, water flooding is one of the most capable in increasing the oil extraction. Physically, it deals with the displacement of two non-miscible fluids to increase oil production.

In the numerical analysis, oil production is stimulated by water flooding in the formation (Barreiras do Boqueirão outcrop). Besides this, the flooding water can be at a different temperature from the initial formation water. In this case, the flooding process will displace the oil toward the production well and will induce changes in temperature inside the formation, affecting directly the fluid properties of the displaced fluids as viscosity and density, which in turn will influence fluid flow and mobility.

Numerical modeling was carried out using the Finite Element program CODE_BRIGHT, which solves in a coupled way the flow equations of water and oil and the internal energy balance (heat equation) for a multiphase porous medium, which in the particular case of the application herein presented is considered a rigid and no reactive porous medium.

2 CODE_BRIGHT MODELING

2.1 THM formulation: theory

Olivella[2] implemented the equations that govern the THM problem for a deformable and multiphase porous medium in a finite element program named CODE_BRIGHT (COupled DEformation, BRIne, Gas and Heat Transport). This program has been tested and applied successfully and its main application is numerical modeling the behavior of engineer barriers used in storage of high-level radioactive waste[3,4]. Due to its general mathematical formulation, CODE_BRIGHT has also been used in other practical engineering applications, such as petroleum engineering problems[5].

The THM formulation considered in this paper is a particular case of the general formulation proposed by Olivella[2], adapted to porous medium with water and oil as fluid phases. Some basic hypothesis of the THM formulation adopted are listed below:

- The porous medium is triphase with two fluid phases (water and oil) and a solid phase.
- Thermal equilibrium is considered between the phases, that means that water, oil and

solid phases have the same temperature.

- Fluid phases are immiscible and there's no chemical reaction between them.
- THM problems state variables (unknowns) are: solid phase velocity, water pressure (P_w), oil pressure (P_o) and temperature (T).
- The medium conservation movement for the fluid phases is reduced to Darcy's law.

The governing equations for the THM problem are balance equations, constitutive equations and definition constraints. Balance equations apply to mass of water (unknown: water pressure, P_w), mass of oil (unknown: oil pressure, P_o), internal energy (unknown: temperature, T), for non isothermal problems and linear momentum (unknown: solid velocities, $\dot{\mathbf{u}}$), when the porous medium is deformable.

The examples presented in this paper are only thermo-hydraulic problems. Porous medium is supposed to be rigid and though mechanical problem is not solved. The equations solved by CODE_BRIGHT in the problems herein presented are:

- Water mass conservation:

$$\frac{\partial}{\partial t}(\rho_w S_w \phi) + \nabla \cdot (\rho_w \mathbf{q}^w) = f^w \tag{1}$$

where ϕ is porosity, ρ_w water density, S_w water degree of saturation and $\mathbf{q}^w$ water volumetric flow, given by Darcy's law. f^w is a water sink/source term, which in the absence of chemical reactions is zero.

- Oil mass conservation:

$$\frac{\partial}{\partial t}(\rho_o S_o \phi) + \nabla \cdot (\rho_o \mathbf{q}^o) = f^o \tag{2}$$

where the terms of this equation are analogous to the terms of equation (1).

- Internal energy conservation:

$$\frac{\partial}{\partial t}(E_s \rho_s (1-\phi) + E_w \rho_w S_w \phi + E_o \rho_o S_o \phi) + \nabla \cdot (\mathbf{i}_c + \mathbf{j}_{Es} + \mathbf{j}_{Ew} + \mathbf{j}_{Eo}) = f^Q \tag{3}$$

The internal energy of each phase is in the storage term. Heat transport by conduction (non advective flow $\mathbf{i}_c$) is added to the advective ones for each phase.

Constitutive equations relate directly or indirectly, the variables that appear in the balance equations with the main unknowns. Darcy's law and the retention curve are examples of constitutive equations. The constitutive equations considered herein are:

Fourier law	Flow by heat conduction	$\mathbf{i}_c$
Darcy law	Water and oil advective flow	$\mathbf{q}_w$, $\mathbf{q}_o$
Retention curve	Water and oil degree of saturation S_w, S_o	$S_w = f(P_o - P_w)$ $S_w + S_o = 1$
Phase density	Water density	ρ_w
Phase density	Oil density	ρ_o

Hydraulic problem of modeling multiphase flow has as fundamental constitutive equation Darcy law, which gives fluid flow in porous medium as a function of its pressure. Darcy flow is given by

$$\mathbf{q}^{\alpha} = -\mathbf{K}_{\alpha}\left(\nabla P_{\alpha} - \rho_{\alpha}\boldsymbol{g}\right) \tag{4}$$

where $\boldsymbol{g}$ is the gravity vector, α is the fluid (water or oil) and hydraulic conductivity tensors are given by

$$\mathbf{K}_{\alpha} = \mathbf{k}.k_{r\alpha}/\mu_{\alpha} \ \ , \alpha = w,o \tag{5}$$

where $\mathbf{k}$ is the porous medium intrinsic permeability (doesn't depend on the fluid), $k_{r\alpha}$ is the relative permeability (depends on the fluid α) and μ_α is the viscosity of fluid α. Definition constraints come out from the definitions of variables, e. g. $S_w + S_o = 1$. Details of the governing equations for the THM problem are described elsewhere[2]. All the coupled equations discretized in CODE_BRIGHT are simultaneous solved by Newton-Raphson's method.

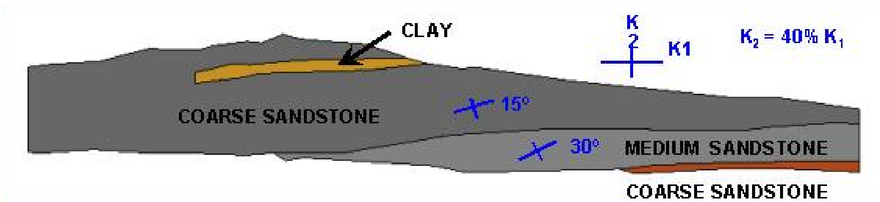
3 BARREIRAS DO BOQUEIRÃO OUTCROP

The formulation described is applied to simulate the multiphase flow of water and oil in Barreiras do Boqueirão outcrop. It is a turbiditic sequence of Maceió Formation, located in the north part of Alagoas basin, in the northeast coast of Brazil. Turbiditic sequences of Maceió Formation aggregate a variety of faciological characteristics similar to the most economically important Brazilian reservoirs[1].

Barreiras do Boqueirão outcrop was characterized with respect to the geometry and faciology based on the metodology of architectural elements analysis. Figure 1 presents a photomontage of this outcrop. Figure 1b presents the geometry and different materials considered in the multiphase flow simulation, considering it as a hydrocarbon reservoir analogous. Materials were defined from the geological characterization previously carried out[1].

The petrophysical data were not determined by the geological characterization, therefore the values adopted in numerical simulations (Table 1) were estimated from Brazilian reservoirs rocks having the same diagenetic evolution of the Maceió Formation. Fluid properties were also based in these reservoirs, considering a depth of 2040m (Table 2). Vertical permeability (Kv) is equivalent to 40% of the horizontal permeability. It's also considered the slope of permeability anisotropy principal direction with the horizontal, as indicated in Figure 1.

(a)



(b)

Figure 1. Barreiras de Boqueirão outcrop: (a) Photomontage; (b) numerical model geometry for multiphase flow in the Analogous.

Table 1 – Materials properties

Materials	Porosity (%)	Kh (mD)
Coarse sandstone	19.7	50.0
Medium sandstone	25.0	100.0
Clay	30.0	0.30

Table 2 – Fluid properties

	Water	Oil
Density (kg/m^3)	1000.0	888.7
Compressibility $(kg/cm^2)^{-1}$	$4.8x10^{-5}$	$3.26x10^{-4}$
Viscosity (mPa.s)	0.5	0.5

The relation between the degree of saturation and capillary pressure is expressed by the retention curve illustrated in Figure 2. This figure also presents the relative permeability curves.

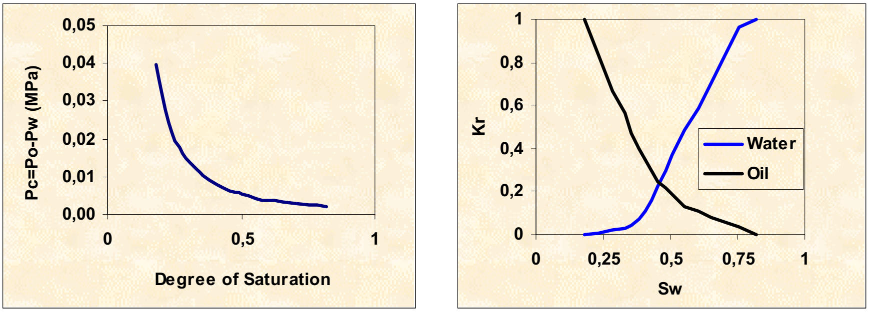


Figure 2.Material parameters for hydraulic problem: (a) retention curve and (b) relative permeability (kr) curve.

4 SIMULATIONS CARRIED OUT

4.1 Base Case

The geometry and materials used in the numerical simulations are the ones described in item 3. The gravity effect in water and oil flow is neglected. Upper and lower boundaries are supposed to be impervious. As initial conditions it was considered P_w=310kg/cm^2 and S_w=10%. The operational conditions adopted are the following:

- Production well: minimum bottom hole pressure of 220kgf/cm^2 and maximum flow of 1m^3/day.
- Injection well: maximum bottom hole pressure of 600kgf/cm^2 and maximum flow of 1m^3/day.

In the analysis carried out it was estimated an exploration period of five years. The petroleum indicators calculated are oil and water accumulated productions and recovery factor (RF)|, gotten by the ratio between the volume of recovered oil and the initial volume of oil estimated on surface.

Exploring one of the main characteristics of the Finite Element Method it was possible to obtain with CODE_BRIGHT a very good discretization (mesh) of the real reservoir geometry (Figure 3), making it possible a detailed identification of the different flow regimes during the five years of exploration. The finite element mesh used in the analysis is bidimensional and relatively fine with 1907 elements and 1046 nodes. It is also indicated in Figure 3 the injection well (water) and production well (oil and water) completion.

The accumulated oil and water production can be seen in Figure 4. The recovery factor for five years was equal to RF=65%. It's important to mention that this high value is basically due to the low viscosity adopted for the oil, almost equal to the water viscosity. Besides this, gas formation was not allowed in the reservoir even after depressurization by opening the production well.

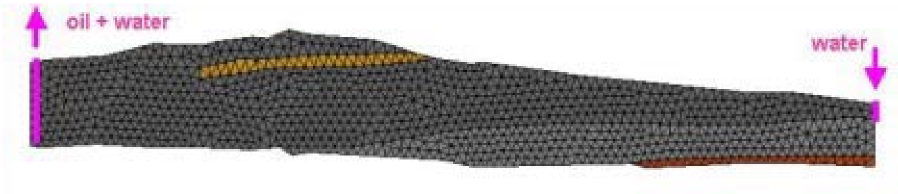


Figure 3. Finite element mesh used in the analysis (1907 elements and 1046 nodes).

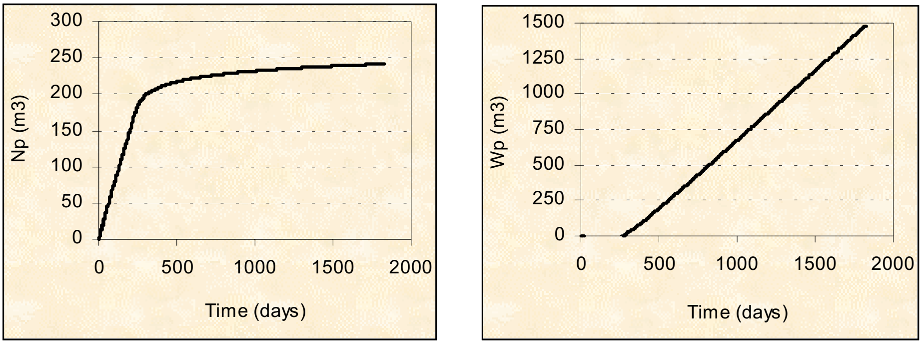


Figure 4. Accumulated oil production (Np) and accumulated water production (Wp).

Figure 5 illustrates the oil displacement in the reservoir by water flooding and distribution of water degree of saturation for 105 and 209 days. In this figure, it's verified that in spite of injected in the upper layer of coarse sandstone, water percolates preferentially by medium sandstone, which is the most permeable layer. In the 209 days distribution of water saturation it can also be seen how the clay layer works as a barrier for the fluids due to its low permeability.

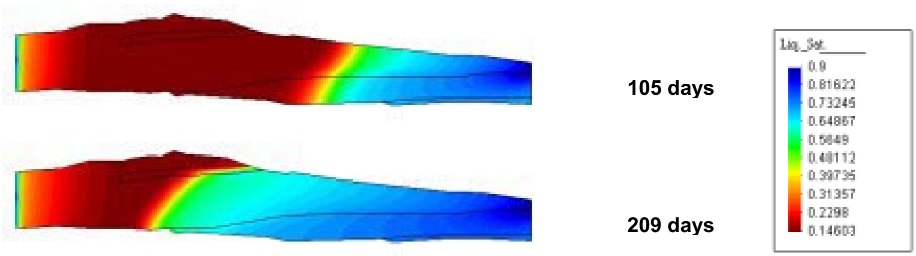


Figure 5. Evolution of water saturation in the Base Case.

4.2 Thermal Case: Hot water injection

In general thermal methods an increase of reservoir temperature is promoted in order to decrease the oil viscosity, which depends on temperature in accentuated way. This turns out in an increase of oil mobility in the reservoir leading to an increase of oil recovery.

The aim of this analysis is to apply the CODE_BRIGHT coupled thermo-hydraulic simulation to a thermal method of heavy hydrocarbons recuperation. Among the thermal methods available, in situ combustion and vapor injection are the most common. However in some situations other methods can also be efficient and economically practicable.

In the example considered it was simulated the thermal method of hot water flooding. This method is particularly useful in mature fields at shallow depth and containing high viscosity oil and also with the presence of geothermal source[6], as for example in Sumatra Field, in Indonesia. Figure 6 illustrates this technique where there is geothermal water available at a temperature higher than the reservoir water.

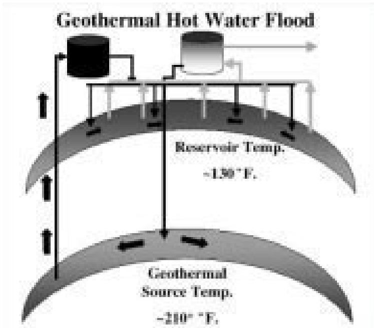


Figure 6. Schematic drawing of hot water flooding, from a geothermal source in a heavy oil reservoir [6].

New rock and fluid properties were considered for the thermo-hydraulic simulation. Table 3 presents specific heat capacity of solid and fluid (water and oil) phases and porous medium thermal conductivity adopted for the model. These values were based on technical literature about the subject[7] and are used only as reference values, which can change with the reservoir (mainly the oil properties).

Table 4 presents fluid's density and viscosity. The value adopted for viscosity was much higher than the value of the Base Case, which was about the water viscosity. Besides this, the dependence of oil viscosity on temperature is illustrated in Figure 7. This new oil property will change drastically the oil recovery in respect to the Base Case (low viscosity oil). Moreover it will also be seen that for heavy oil, oil recovery will change with water flooding temperature.

Table 3. Thermo-hydraulic parameters[7]

Specific heat capacity at constant pressure
Oil: $c_o = 2092$ J/kg/°C
Water: $c_w = 4184$ J/kg/°C
Rock: $\rho_s\, c_s = 2413$ kJ/m³/°C
Porous medium thermal conductivity
$k_T = 0.1661$ W/m/°C
Fourier law: $i_c = k_T \nabla T$

Table 4. Properties for thermal problem: fluids phase's viscosity and density.

Viscosity[8]:

$$\mu_o = \exp(\exp(a_4 + b_4 \ln T)) - 1.05$$

$$\mu_w = \frac{2185}{(40.12 + 0.0051547T)T - 1000}$$

where μ_o and μ_w in cP and T in °F

Density:

$$\rho_o = \rho_{o,ref}\left(1 + c_o\left(P_o - P_{o,ref}\right) - \alpha_o\left(T - T_{ref}\right)\right)$$

$$\rho_w = \rho_{w,ref}\left(1 + c_w\left(P_w - P_{w,ref}\right) - \alpha_w\left(T - T_{ref}\right)\right)$$

	$\rho_{\iota,ref}$ (kg/m³)	c_i (MPa⁻¹)	α_I (°C⁻¹)	a_4	b_4
Oil	888.7	3.14e-5	2.28	10.876	-2.0989
Water	1000	4.7e-6	2.28	-	-

Two more cases were simulated, both considering the same initial temperature of 30°C. In the first isothermal case with heavy oil, the water was injected at a temperature equal to the initial (30°C). In the second case (with heavy oil), this time non isothermal, it was considered a temperature of 100°C for the flooding water.

Recovery factor for these cases, calculated for 5 years exploration are:

- Base Case (low viscosity oil): RF = 65%
- High viscosity oil Cases:

Flooding water at 30°C: RF = 35%

Flooding water at 100°C: RF = 54%

It's verified that the recovery factor value of 65% from Base Case drops a lot (35%) when it's considered heavy oil (high viscosity) under isothermal conditions, as it was expected.

Considering only the heavy oil cases, water flooding at 100°C increases oil recovery factor from 35% to 54% due to the large oil mobility by temperature effect. These results are shown in Figure 8 by water saturation distribution after 5 years water flooding. The case with water at 100°C presents a greater oil displacement by water flooding, presenting water degree of saturation larger than the isothermal case

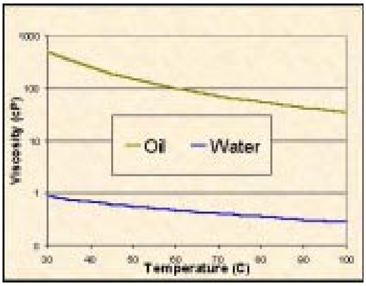


Figure 7. Oil and water viscosity as function of temperature.

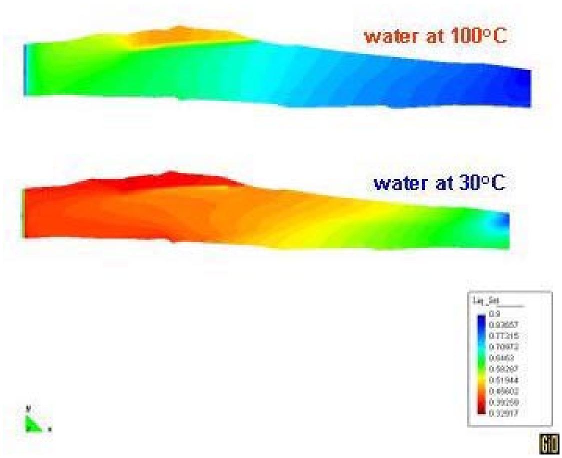


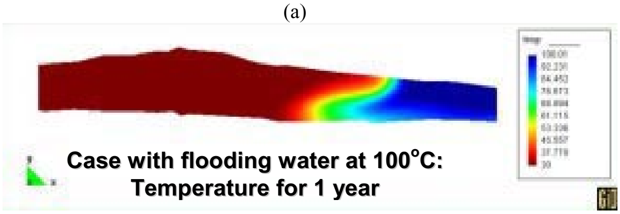
Figure 8. Water saturation distribution after 5 years water flooding at different temperatures (100 e 30°C).

These results demonstrated that this method can be very efficient to enlarge oil recovery from a reservoir with high viscous oil. On the other hand it should be emphasized the consideration of the hypothesis of an ideal situation for the upper and lower reservoir boundaries as thermal isolating. Heat loss should always be expected for the contiguous layers, which obviously decrease the efficiency of thermal method.

Temperature and water saturation distribution for 1 and 2 years of injection are illustrated in Figures 9 and 10. These figures show how the thermal front goes with the water saturation front, indicating the predominance of advection as heat transport mechanism.

Finally, this numerical study demonstrated that CODE_BRIGHT is capable to perform thermo-hydraulic simulations of thermal methods for enhanced oil recovery of heavy hydrocarbon reservoirs.

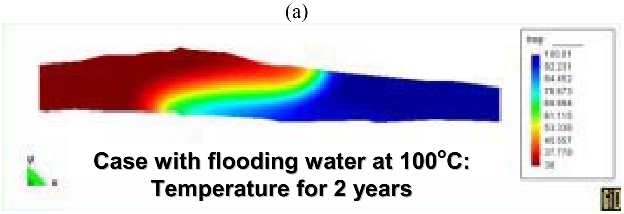
(a)



(b)

Figure 9. (a) Water saturation and (b) temperature distribution for 1 year analysis.

(a)



(b)

Figure 10. (a) Water saturation and (b) temperature distribution for 2 years analysis.

5 CONCLUSIONS

The numerical simulations presented correspond to a parametric study, which aims the better understanding and verification of multiphase flow modeling of hydrocarbon reservoir analogous.

The analysis carried out with CODE_BRIGHT showed the influence of considering heterogeneous layers in reservoir flow regimes. It was demonstrated that water percolates preferentially through the most permeable layer and, in another situation, the lowest permeability layer creates a barrier for fluid flow.

In the simulation analysis of hot water injection, the increase of temperature results in a decrease of oil viscosity, increasing oil mobility. The results achieved demonstrated that this method can be efficient on incrementing the recovery factor of heavy hydrocarbon reservoirs.

It was also pointed out that the code is capable to perform simulations of flow of oil, water and heat in Petroleum Engineering.

6 ACKNOWLEDGEMENTS

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