EFFECT OF OIL TYPE ON SWEEP EFFICIENCY OF WATER INJECTION UNDER FRACTURING CONDITIONS PROCESS

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Abstract. *Water injection performance depends on the oil and petrophysical reservoir properties and fluid-flow characteristics. When water is injected into the reservoir at pressures above formation fracturing pressure, the effects of these properties over the reservoir model performance, and specially, on waterflooding sweep efficiency, become critical. Quantification of these effects, using parameters such as the Recovery Factor (RF) and Net Present Value (NPV), is important for the injection project dimensioning and to determine the feasibility and usefulness of the injection process to be implemented.*

The objective of this work is to quantify, using Sweep Efficiency and Net Present Value as study parameters, the effects of three different fluid models on the production performance during a waterflooding under fracturing conditions. The methodology proposed considers the simulation of scenarios in which the injectivity loss is represented by an analytical decline equation, and the fracture is represented using a virtual horizontal well.

The results show the applicability of water injection under fracturing conditions in different oil type scenarios. Also, this work shows the importance of the reservoir parameters into the injectivity loss and fracture propagation models, and the significance of the RF and NPV in the quantification of these effects.

Keywords: Reservoir simulation, Injectivity loss, Water injection, Fracture propagation, Sweep efficiency.

1. INTRODUCTION

It is well known that water injection is the most common method for oil recovery and pressure maintenance, this process involves different variables that shall be taken into account in order to evaluate properly the reservoir performance. Although the injection under fracturing conditions can improve the reservoir performance, this process presents some disadvantages, and according to Altoé *et. al*. (2004) the injectivity loss is the most important problem associated with water injection and it has direct relation with the quality of the water and the reservoir properties. This phenomenon makes necessary an increase on the injection pressure in order to maintain a constant water injection rate.

Different solutions can be applied to improve the performance of the water injection process. One of these, according to Palsson *et. al*. (2003) is to improve the water treatment system; other is the removal of the formation damage using mechanical and chemical treatments. At an academic level, some studies such as Gadde and Sharma (2001), that developed an analytical model to study the decline caused by injected fines; or Bedrikovetsky *et. al*. (2005), that developed a method to calculate the injector well impairment from laboratory and field data, aim to model the influence of formation damage on the reservoir behavior and the possible forms to solve the problem.

Other way to attack the injectivity decline is water injection under fracturing conditions. This option allows reestablishing the well injectivity creating high conductivity channels and avoiding the implementation of complex systems for water treatment. However, a possible consequence of injecting water above formation fracture pressure is the canalization of the injected water throughout the created fracture towards producing wells leading to a water recirculation, with its negative results for the production performance. All these factors makes that a careful analysis must be done, to locate correctly the production wells, in order to increase sweep efficiency.

Considering the factors above cited, geomechanical simulator can be considered an useful tool to analyze and study fracture behavior under water injection conditions, but this type of software can present high time consumption when used in full field applications. Other approximations to model induced fractures by water injection, using numerical simulators, are local grid refinements in grid blocks with high permeability, transmissibility modifiers or the use of effective radius to represent the fracture. Another method to represent a fracture induced by water injection consist in use a virtual horizontal well (Montoya *et al*, 2006). This approximation to model fractures avoids grid refinement and can be easily implemented into adjusted reservoir simulation models. Virtual horizontal well do not requires any grid modification. However, this approach depends on the virtual horizontal well index calculation.

Besides the reservoir properties, the fluid characteristics are fundamental for the analysis of the reservoir behavior in order to achieve a better understanding of the injection process and its effects on the sweep efficiency.

This work aims to study the modeling of the injection under fracturing conditions process. Also is analyzed the effect of anisotropies and reservoir fluid type on the sweep efficiency.

2. PROCESS MODELING

To better understand the effect of the reservoir and fluid properties on the sweep efficiency of the injection under fracturing condition process, it is necessary to illustrate how the whole process is modeled in commercial simulators.

The coupling of geomechanical calculations and flow simulation is a fundamental part of the modeling stage, nevertheless, the access to a full coupled simulator is limited and a hi the most of the times and a full coupled simulation presents a high computational consumption time, making necessary the use of the results obtained from an in-house geomechanical simulation to represent the fluid flow into the reservoir rock as the rock properties vary with time.

In commercial simulators, it is common to represent the fractures by means of mathematical models, grid refinement or transmissibility modifiers. In this study the use of virtual horizontal wells is proposed to model the fracture opening and propagation process.

2.1. Injectivity loss modeling

The injectivity loss is modeled by the variation of the terms of the Well Index (WI) equation. These variations include properties as well block permeability, the formation damage factor (skin factor) and their combinations given by the Eq. (1).

$$WI = \frac{2\pi h k_b w_{frac}}{\ln\left(\frac{r_e}{r_w}\right) + s} \tag{1}$$

The mathematical model for the permeability variation in the damaged region that was used in this study considers a hyperbolic permeability decline. Bedrikovetsky *et al*. (2001) proposed this model in order to describe the permeability decline as a function of the time, as it is shown by Eq. (2).

$$k_s = \frac{k_{ij}}{c_0 + c_1 t} \tag{2}$$

In Eq. (2) k_s is the absolute permeability of the damaged region, k_{ij} is the original injector well block permeability, and c_0 and c_1 are the constants that determine the decline trend of the curve with time (1.00 and 1.25 E –02 respectively). Figure 1 shows the permeability behavior in the damaged region normalized by the block permeability as function of the simulation time.

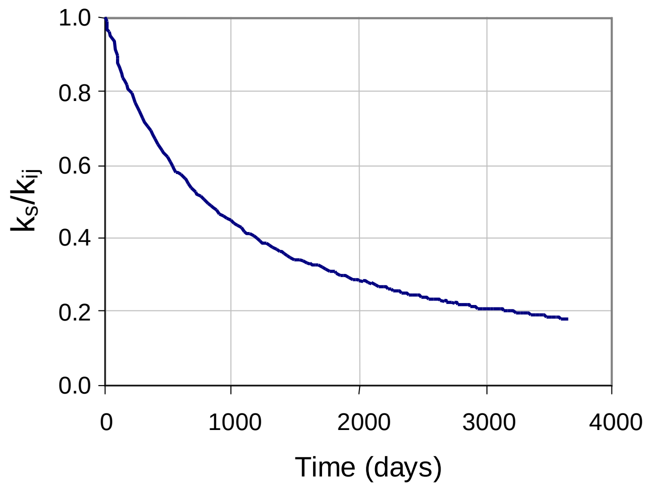

Figure 1. Permeability decline in the damaged region

Due to the lack of bibliographical sources that study the relationships between the fracture length (L_f) and the skin factor (s) in injector wells under fracturing conditions, the Cinco-Ley and Samaniego (1981) model, which approximates the relation of a skin factor value to a fracture length value, has been used. In the realized tests, this model is applied for any fracture length value obtained from the geomechanical simulation. The Cinco-Ley and Samaniego model is based on the fracture dimensionless conductivity factor, given by:

$$F_{DC} = \frac{k_f w}{k L_f} \tag{3}$$

In Eq. (3) k_f is the fracture permeability, w is the fracture width, k is the formation permeability, and L_f is the fracture length. Equation (4) gives the relationship between the fracture dimensionless conductivity and the equivalent skin factor, that is represented in Fig. 2.

$$S_f + Ln\frac{L_f}{r_w} = -0{,}6751 Ln(F_{DC}) + 1{,}508 \tag{4}$$

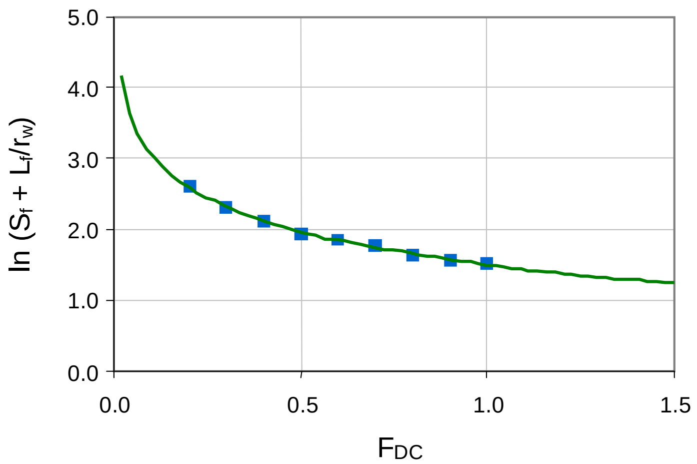

Figure 2. Equivalent skin factor as function of fracture dimensionless conductivity.

Fracture permeability is given by the following expression (Aguilera, 1980):

$$k_f = 84 \times 10^6 w^2 \tag{5}$$

In Eq. (5) the fracture width values is obtained from geomechanical simulation, and for the purpose of this work a mena values of 2.45 E-03 meters is used in the fracture permeability calculation.

Once calculated the values of the permeabilities of both the well block and the damaged zone, it is necessary to calculate the bulk permeability of the injector well block. For this, the harmonic mean formulation, shown in Eq. (6) is used.

$$k_{bh} = \frac{Ln\left(\frac{r_e}{r_w}\right)}{\frac{1}{k_s} Ln\left(\frac{r_s}{r_w}\right) + \frac{1}{k_b} Ln\left(\frac{r_e}{r_s}\right)} \tag{6}$$

In Eq. (6) r_w and r_e represent the well and the equivalent radius respectively; and r_s is the radius of the damaged region.

2.2. Fracture generation and propagation simulation modeling

The use of transmissibility modifiers as a method for representing the fracture generation and propagation, as proposed by Souza *et al* (2005), consists in a grid refinement in the fracture propagation direction, the definition of thin grid blocks and the transmissibility value multiplication for the block that content the fracture. As the transmissibility between two grid blocks is a function of the geometric, rock-fluid, and rock properties, the multiplying factor favors preferably a direction instead the other.

The virtual horizontal well approach to represent the fracture growth is based in the analyses of Ogunsanya (2005), who considered the horizontal well as a small height fracture. In this model, the well parameters are calculated as function of the geometric characteristics of the fracture, avoiding the high time consumption of the fully coupled simulators with geomechanics. The well index is calculated as described previously and divided for the number of perforations opened accordingly with the fracture propagation profile obtained from geomechanical simulation (Muñoz Mazo *et al*, 2006).

Figure 3. shows the virtual horizontal well approach.

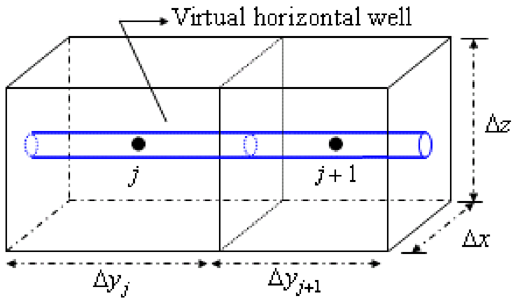

Figure 3. Virtual horizontal well approach for representing the fracture propagation.

2.3 Sweep efficiency analysis

Taking into account the simplifications of the model, for the sweep efficiency determination, the assumption of the vertical efficiency of the injection process for the model is 1, since the homogeneous condition of the model and the meaningless of the gravitational effects is made. In consequence, the sweep efficiency of the process is studied using as main parameters the Recovery Factor (RF) and the Net Present Value (NPV).

3. METHODOLOGY

3.1. Simulation models

The simulation models that were used to obtain the results reported in this work consist in a Cartesian grid, with 51x51x10 active cells. Each cell has 30 x 30 x 4 m and the main reservoir properties are shown in Tab. 1. The production strategy implemented for the simulations represents a five spot arrangement, with a central vertical injector well, and four vertical producer wells, as it is shown in Figure 4.

Table 1. Reservoir properties

Property	Nomenclature	Value
Porosity	ϕ	25%
Horizontal Permeability	kx = ky	500 mD
Vertical Permeability	kz	200 mD
Water viscosity	μ_w	0.9 cP
Relative Permeability to oil	kro’	0.5833
Relative Permeability to water	krw’	0.3593

For the purpose of this work, which is to analyze the effect of the oil type on the sweep efficiency of the waterflooding under fracturing conditions, three different oil types are used:

- Light oil (817.2 kg/m³, 0.6 cP).
- Intermediate oil (871.5 kg/m³, 3.4 cP).
- Heavy oil (924.8 kg/m³, 17.1 cP).

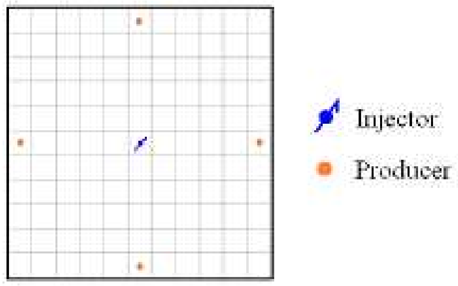

Figure 4. Well arrangement in the simulation grid.

3.2. Simulation analysis

The simulation process is carried out in three stages: First, the model is simulated without considering both injectivity loss and fracturing presence (this is the "original model", named as NLNF for No Loss – No Fracture).

Then, the injectivity loss is introduced into the simulation model by modifying the simulation WI for the time steps, reproducing in this way the effect of the formation damage, and maintaining the pressure of the reservoir below the value of fracture pressure (WLNF, for With Loss – No Fracture). The purpose of this stage is to establish the effect of the formation damage on the original model.

Finally, when the well bottom-hole pressure reaches the fracturing pressure, the fracture propagation is introduced. Fracture propagation is represented using a horizontal virtual well, whose perforations are open following the fracture propagation profile determined from the geomechanical simulation (WLWF, for With Loss – With Fracture).

As a mechanism to establish the effect of both the injectivity loss and the fracturing on the reservoir behavior, it is necessary to compare the results obtained from the stages mentioned above. For this, two parameters, DECLI and RECOVI are introduced.

The Decline Index (DECLI) is the ratio between the values obtained from the simulation of the cases that only involve the injectivity loss due to the formation damage (WLNF) and the cases with the original model (NLNF). DECLI values are smaller than 1, indicate that, due to the injectivity loss, there was a decrease in the control indicators used for the analysis. Values of DECLI equal to the unit indicate that the injectivity loss did not affect the reservoir performance, and values larger than 1 indicate that even with injectivity loss the productive behavior of the system was improved.

In the other hand, the Recovery Index (RECOVI) is the ratio between the obtained values of the simulation of the cases that involve the fracture presence (WLWF) and the obtained values of the other two cases: (1) the original case (NLNF) and (2) the case that takes into account the injectivity loss (WLNF). Recovery Index values smaller than 1 will indicate that the presence of the fracture did not improve the behavior of the system, considering, or not, the injectivity loss. Otherwise, values equal or larger than 1 show that the fracture got, at least, to equal the indicators of the cases to the which it is compared, showing improvement indicators of behavior of the reservoir when the values of the index are larger than 1. Besides the Recovery Factor (RF) and the Net Present Value (NPV) as control parameters, Cumulative Production of Water (W_p) and the Cumulative Water Injection (I_w) are used the to accomplish a global analysis. The economic scenario for the calculation of NPV is shown in the Tab. 2.

Table 2. Economic scenario for the simulations.

Taxes	
Discount rate (%)	10
Royalties (%)	10
Other (%)	36.65
Price	
Oil price (US$/m³)	220.15
Investments	
Platform (US$)	10000000
Producer or injector well (US$)	2000000
Costs	
Oil production (US$/m³)	37.74
Water production (US$/m³)	4.03
Water injection (US$/m³)	4.03

For the analysis of the obtained results, mobility ratio is used as comparative parameter, the calculation of this factor is given by Eq. (7):

$$M = \frac{k'_{rw}\mu_o}{k'_{ro}\mu_w} \tag{7}$$

In Eq. (7) M is the mobility ratio, k_{rw} and k_{ro} are the terminal relative permeabilities to water and oil respectively; and μ_o and μ_w are the oil and water viscosities respectively.

4. RESULTS AND DISCUSION

4.1 Mobility ratio determination for the oil types

The mobility ratios calculated based in the oil characteristics and using Eq. (7), are reported in Tab. 3.

Table 3. Mobility ratios for the tested oil types.

Oil type	μ_o	M
Light	0.6	0.4
Intermediate	3.4	2.3
Heavy	17.1	11.7

4.2 Effect of the injectivity loss in sweep efficiency

To analyze the impact of injectivity loss in the reservoir performance the Decline Index (DECLI) and the control parameters described in Section 3.2 are used. The results are listed in Tab. 4. and are illustrated in Fig. 5.

Table 4. DELCI values for the tested oil types.

	DECLI			
Oil type	RF	W_p	I_w	NPV
Light	0.72	0.02	0.63	0.86
Intermediate	0.87	0.18	0.82	0.91
Heavy	0.47	0.00	0.38	0.41

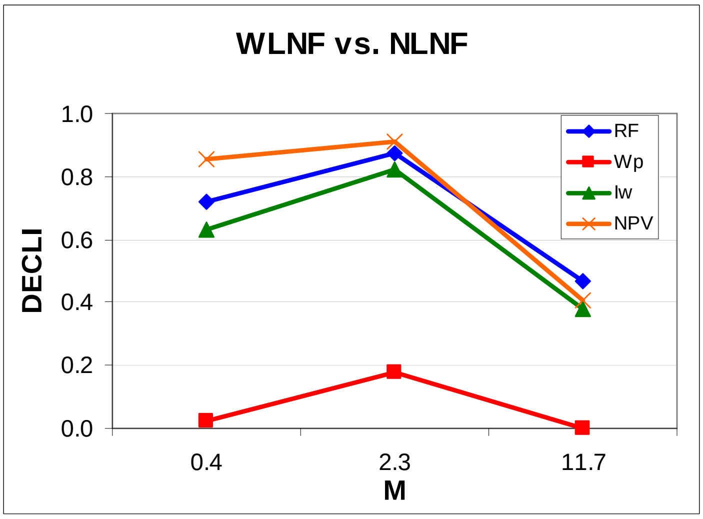

Figure 5. Effect of injectivity loss on control parameters.

From Fig. 5 it can observed that DECLI, for all the indicators and for all the three different mobilities, has values minor than 1. This indicates the negative effect of the injectivity loss on the reservoir performance, since both the oil production and the water injection (and in consequence the waterflooding sweep efficiency) present a significant diminution as the permeability reduction is introduced to the simulation model.

Figure 5 also shows that among the control parameters, the cumulative water production (W_p) experienced a more accentuated diminution. This behavior is logical consequence of the progressive diminishing of the water intake to the reservoir (decline in I_w) due to injectivity loss, and this affects directly the recovery factor and the economic performance of the model, leading to decay in the sweep efficiency of the waterflooding process.

For the three fluids analyzed, Fig. 5. shows that the effect of injectivity loss is more evident for high mobility ratios (heavier oils) as a consequence of more difficult drive of a heavy oil by a lighter water, affecting all the contrl parameters used for this analysis.

4.3 Effect of the fracture propagation for cases with injectivity loss problems

The fracture effect on the performance of the cases with injectivity loss is made using the Recovery Index (RECOVI); the results are shown in Tab.5. and Fig. 6.

Table 5. RECOVI values for the tested models.

	RECOVI			
Oil type	RF	Wp	Iw	NPV
Light	1.36	40.11	1.54	1.11
Intermediate	1.13	5.08	1.20	1.08
Heavy	1.59	**	1.63	1.54

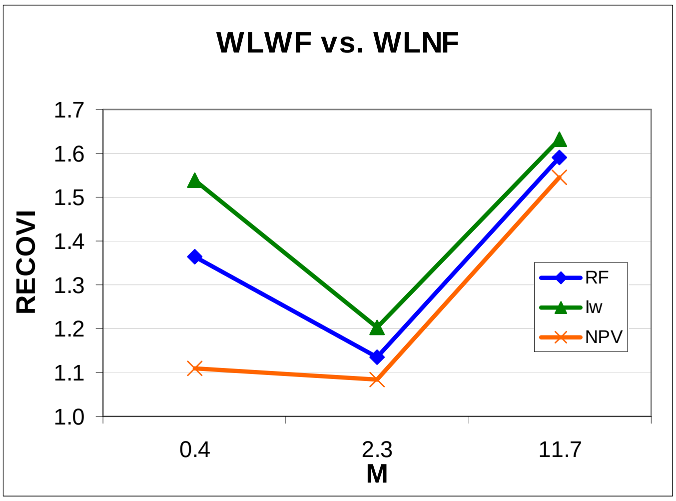

Figure 6. Effect of fracture presence on control parameters.

The values reported in Tab. 5. show how the fracture affects positively the reservoir performance. The RECOVI values, greater than 1 indicate that the control parameters experienced an increase because of the fracturing process if compared with the cases that only consider the injectivity loss. For the heavy oil the value of W_p is not reported because its calculation implies a division by zero, since the water production for the case with injectivity loss was absent and for the case with fracture presence a significant quantity of water was produced as consequence of the higher quantity of water entering the reservoir throughout the fracture.

Figure 6. presents the behavior of RECOVI for the control parameters. It is important to outstand that the absence of the control parameter W_p is due to factors above explained. And it can be observed that, as observed in the previous section, the effects are more accentuated in the cases with a higher mobility ratio.

4.4. Comparison between cases with fracturing presence and cases without injectivity loss (original model)

RECOVI values are used to compare the WLWF cases and the NLNF cases. The values lower than 1 in Tab. 6 indicate, mainly, that the waterflooding under fracturing conditions process does not get to improve neither the behavior (nor the sweep efficiency) of reservoirs with injectivity loss problems until the level of the original reservoir models.

Analogously to the previous sections, form Fig. 7 it can be observed that the difficulty of the fracture to increase the performance levels to the original case is more evident for models with high mobility ratios

Table 6. Recovery index values for the tested oil types.

	RECOVI			
Oil type	RF	Wp	Iw	NPV
Light	0.98	0.88	0.97	0.95
Intermediate	0.99	0.90	0.99	0.98
Heavy	0.74	0.01	0.62	0.63

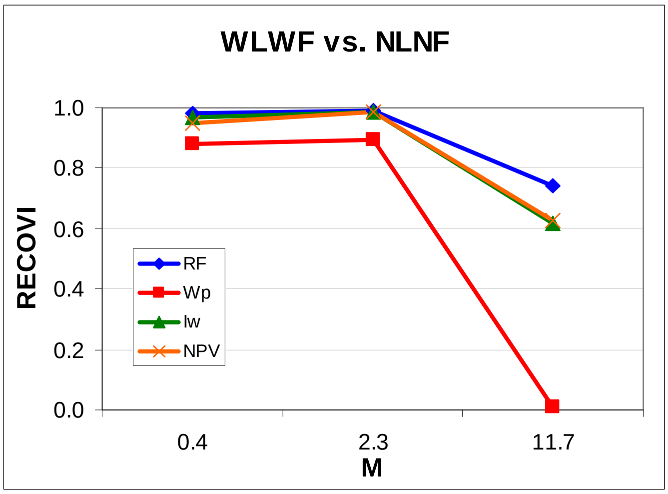

Figure 7. Comparison between fractured and original cases.

To better illustrate the whole process, in Tab. 7 and Fig. 8 are presented the effects of the different mobilities and the simulation stages on the recovery factor of the tested models.

Table 7. RF behavior for the tested oil types.

		WLNF vs. NLNF	WLWF vs. WLNF	WLWF vs. NLNF
		DECLI	RECOVI	RECOVI
Oil type	M	RF	RF	RF
Light	0.4	0.72	1.36	0.98
Intermediate	2.3	0.87	1.13	0.99
Heavy	11.7	0.47	1.59	0.74

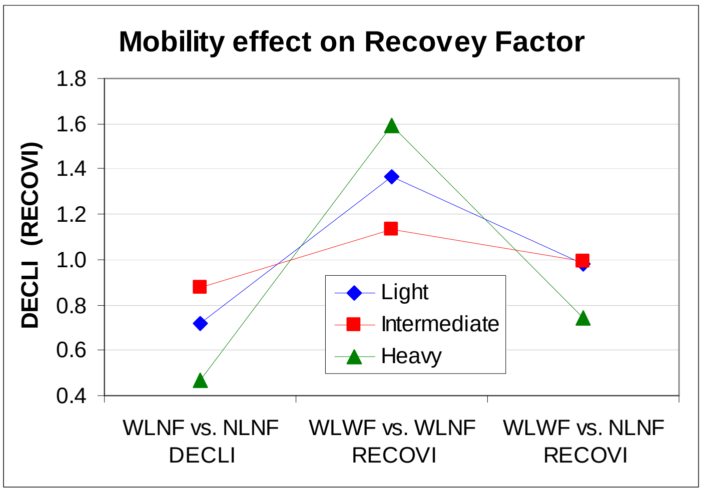

Figure 8. Effect of mobility on the Recovery Factor of the tested models.

In Fig. 8. it is possible to observe that the effects of the injectivity loss (WLNF vs. NLNF) and the fracture propagation (WLWF vs. WLNF and WLWF vs. NLNF) affect in the same way the three oil types tested. Also, it is possible to show how, for heavier oils, the reduction due to the injectivity loss, the increment due to the fracture propagation and the difficulty to restore the production to the level of the original model is more accentuated, evidencing the existing relation between the oil properties and the sweep efficiency of the cases of waterflooding under fracturing conditions.

5. CONCLUSIONS

- The impact of injectivity loss and the fracture propagation on the reservoir performance leads to the research for more realistic and reliable tools to model the process in reservoir simulators. The development of these computational aids implies that subjects, as geomechanics and formation damage analysis, shall be coupled as most as possible.
- This coupling, some times, is not totally available in commercial reservoir simulators, and makes that solutions that present high time consumption, as the implementation of in-house coupled simulation, shall be the option to be adopted in order to analyze the effects of the process on the reservoir sweep efficiency.
- Other solution, as the described in this work, is the use of the results obtained from non-commercial geomechanical simulation and use them, jointly with analytical models, to modify some parameters in commercial simulator, in order to represent the whole process of injectivity and fracture propagation in a more coherent way, taking advantage of the simulator resources and avoiding high time consumption.
- The results show that the waterflooding under fracturing conditions, in spite of to be a useful tool for overcoming the problem of injectivity loss, increasing the sweep efficiency, it cannot to restore the reservoir performance to the level of models that do not present neither injectivity loss nor fracture propagation.
- This effect can be observed for all the three oil types tested in this study, and can be established that high mobility ratios affect in a more accentuated way the behavior of the reservoir during the process, this is, a more sensitive reduction of the performance of the reservoir due to the injectivity loss, a greater increase of the reservoir production and injection due to the fracture propagation, and a more evident difficult to restore the performance indicators to the level of the original models, without neither injectivity loss nor fracture propagation.
- The analysis of the effects of both injectivity loss and fracture presence on the behavior of the wells, aligned and perpendicular to the fracture propagation direction, jointly with the oil mobility variation, is proposed here as a next step in the study of the waterflooding under fracture conditions process.

6. ACKNOWLEDGEMENTS

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