COMPOSITIONAL FLOW SIMULATION APPLIED TO GAS TRACERS' STUDY IN A RESERVOIR RECOVERED BY WAG-CO2 INJECTION

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Abstract, *Tracers have been used to contribute to the understanding of the flow characteristics of the reservoir and to help with the history matching of the simulation model so that it represents, in a more reliable manner, the real reservoir. This work's goal was to develop simulation studies of tracer associated with enhanced recovery methods such as WAG-*CO_2*. The simulations were performed in the Computer Modeling Group (CMG) simulation package. This work adopts a methodology that involves the creation and insertion of tracer components to the main fluid of the reservoir. Some fluid model tests were developed in which sensibility analyses were applied to both gas and oil reservoirs. Then, a simulation study of tracer injection in an oil reservoir subjected to the WAG-*CO_2 *recovery method was made; one of the studies was on how the reservoir's pressure influences the miscibility between injected fluid and reservoir fluid. The obtained results were used to reappraise the production strategy related to the location and number of wells. The economic analysis revealed that the new strategy allowed an increment of the production project's NPV (Net Present Value) and proved to be the lowest risk choice within the production context.*

Keywords: *Enhanced Recovery; Tracers' Simulation; Compositional Simulation; WAG-*CO_2*.*

1. INTRODUCTION

The oil industry constantly deals with various uncertainties and associated risks in all of the phases of an exploration and production project of a field, that is, from the discovery of potential reserves to the exploitation of hydrocarbons. It is only during the development of the production phase that some data can be obtained, thus minimizing the uncertainties.

Studies involving tracers' injection into reservoirs along with the fluids injected for recovery purposes may favor the reduction of uncertainties as information such as well communication, sweep efficiency, preferred flow paths, permeability layering and the efficiency of the recovery method to which it is associated is obtained (BRIGHAM & ABBASZADEH-DEHGHANI, 1987).

One of the main tools used by the industry to study and predict the reservoir's behavior is the numerical flow simulation. It allows studying the variation of several parameters that are critical to the injection and to the production, in order to reach the best production strategy, making it possible to create boundary conditions for possible operational and economic problems. The flow simulation can incorporate the tracer injection and the information obtained with it, so that a better adjustment of the reservoir model can be achieved, thus better representing reality.

1.1. Objectives

The present work has the objective of developing simulation studies of tracers injection into reservoirs that are being produced through recovery methods that employ injection of CO_2 and of WAG-CO_2, so that the tracers' production response can be related to the recovery method effects, to subsidize production strategy reappraisal and to measure the consequent economic benefit.

1.2. Methodology

The main tools in this study are CMG's module *Winprop®* and compositional simulator GEM. A fictitious simulation model was constructed and then used to represent both gas and oil reservoirs.

In the gas reservoir model, sensitivity studies were performed for testing the compositional simulation along with the tracer component in an environment where the partitioning effect of the tracer into the oil phase was minimized. In the oil reservoir model, the recovery method WAG-CO_2 was incorporated and studied through sensitivity analyses; tracer production studies subsidized changes in the production strategy.

2. RESERVOIR SIMULATION MODEL

The reservoir model consists of 167790 blocks, its extension in I is 70 cells, 141 in J, and 70 in K (70 x 141 x 17). Each of the cells has the respective average dimensions in I, J and K: 95 m, 100 m, and 3.5 m. Figure 1 presents the 3D model and the completed wells. The grid lines have been omitted for better visualization. The blue arrow points north.

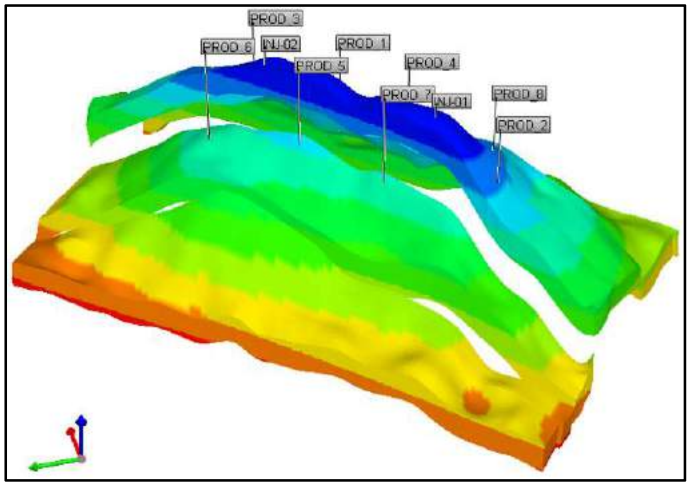

Figure 1. Simulation model 3D representation

The reservoir is located within the depths of 2521 and 2955 m and has 4 faults as presented by the grid top in Figure 2. Figure 2 also shows the reservoir divided into 4 sectors; the data from sectors 2 and 3 are known and were used to populate the rest of the reservoir through interpolation. In other words, only the region composed of sectors 2 and 3 have well data (shape tests, well log and petrophysical analysis); for the other sectors, the distribution of the properties was performed by analogy and same fluid contacts assumption.

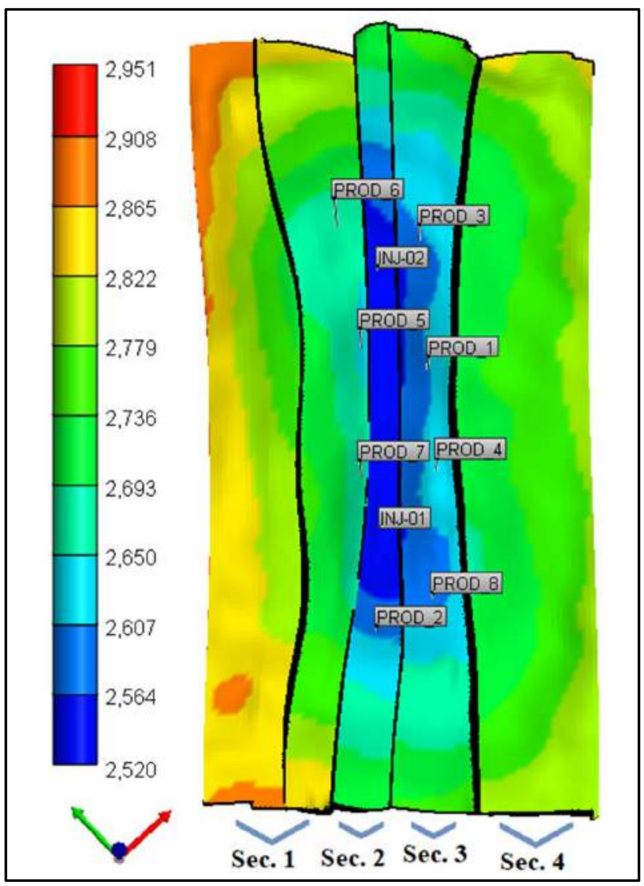

Figure 2. Reservoir divided into sectors

The reservoir's average porosity is 15.26%. Figure 3 is a JK cross-section of the reservoir, in which porosity distribution is shown. The pore volume of the reservoir is 6.39E+8 m^3, being 1.78E+8 m^3 filled with hydrocarbons.

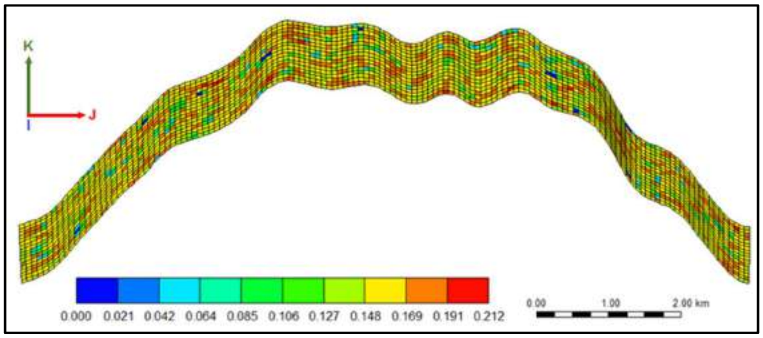

Figure 3. Porosity distribution, JK cross-section

The reservoir's average permeability is 80.93 mD, as presented in Figure 4, no large variation is seen.

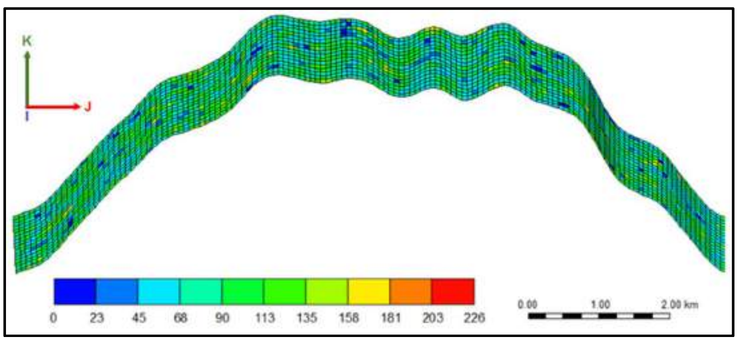

Figure 4. Permeability distribution, JK cross-section

The defined initial conditions were reference depth (2521.22 m), reference pressure (31576.4 kPa) and oil/water contact depth (2740 m). Figure 5 presents the tridimensional model of the reservoir, where oil/water contact can be seen; the orange color represents the oil zone, while green represents the water zone.

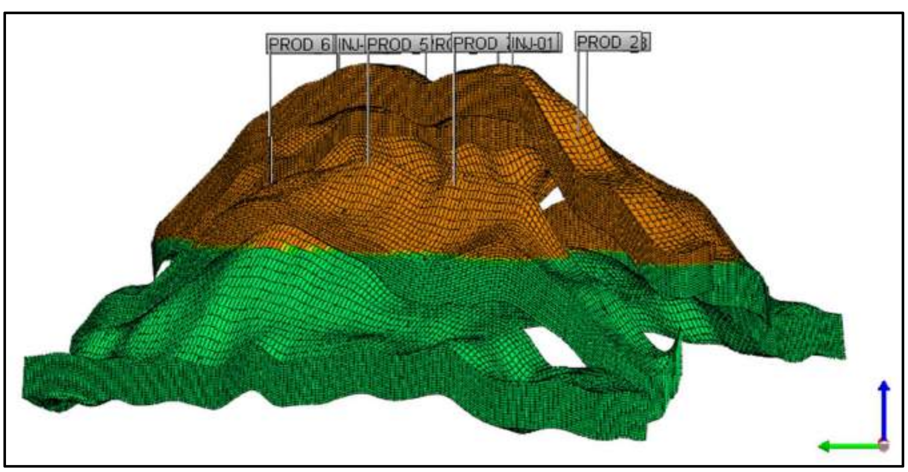

Figure 5. Tridimensional model

2.1. Gas reservoir model

For this reservoir model, the input fluid was the one shown in Table 1.

Table 1. Simulated gas components

Components	Molar Fraction
CO_2	0.0013
CO_2-1	0
CO_2-2	0
N_2	0.0244
C_1	0.7445
C_2-C_3	0.1201
IC_4-C_6	0.0334
C_7-C_9	0.0472
C_{10}-C_{11}	0.0192
C_{12+}	0.0099

This fluid was used in studies related to simulation response due fault presence, inserted discontinuities in the model (high and low permeability) and due permeability layering contrast. Then, a sensibility study was made by varying the injection form (pulse and continuous) and tracer concentration. Gas was used as the reservoir main fluid, so that tracer partition into the oil phase was minimized.

The tracers were injected along with CH4 (methane), each tracer was attributed to one of the two injectors so that the injected fluid behavior could be analyzed.

2.2. Oil reservoir model

The fluid for the oil reservoir is shown in Table 2. Two components were introduced in this model with the function of being the tracers, each of them injected through a different injector only during the gas injection (CO_2), in other words, there is no tracer injection along with water.

Table 2. Simulated oil components

Components	Molar Fraction	Components	Molar Fraction
CO_2	0.0037	FC_8	0.0180
CO_2-1	0	FC_9	0.0147
CO_2-2	0	FC_{10}	0.0114
N_2	0.0017	FC_{11}	0.0093
CH_4	0.6325	FC_{12}	0.0085
C_2H_6	0.0829	FC_{13}	0.0088
C_3H_8	0.0538	FC_{14}	0.0076
IC_4	0.0103	FC_{15}	0.0067
NC_4	0.0193	FC_{16}	0.0049
IC_5	0.0056	FC_{17}	0.0044
NC_5	0.0085	FC_{18}	0.0042
FC_6	0.0115	FC_{19}	0.0035
FC_7	0.0110	C_{20+}	0.0572

3. RESULTS

The field is a fictitious one and is located close to another field, where high amounts of CO_2 are produced. This neighbor field injects some of the CO_2 for its own recovery of hydrocarbons and exports the remaining CO_2 for this work's field, therefore the chosen recovery method was WAG-CO_2.

3.1. Results of tracing study on gas reservoir model

For the gas model simulations, the reservoir's fluid is the one presented in Table 1. Figures 6 and 7 present tracers' 1 and 2 mass flow respectively. The tracers were injected during the beginning of the production phase as a month-long pulse at a concentration of 10% mole of the injected fluid. The absence of tracers in the production of the wells 5, 6 and 7 shows that this region has no hydraulic communication with the rest of the reservoir; this is due to the presence of the sealing fault between sectors 1 and 2. A close in the production of the wells 1 and 4 would show small tracer production coming from the injectors of the other injection pattern, this is due to the presence of the faults, which cause the fluids to be guided through the fault's extension and then be produced, following the lower pressure caused by the production well. In a real case, all of this information obtained from the simulations could be used for history matching and consequent simulation model adjustment.

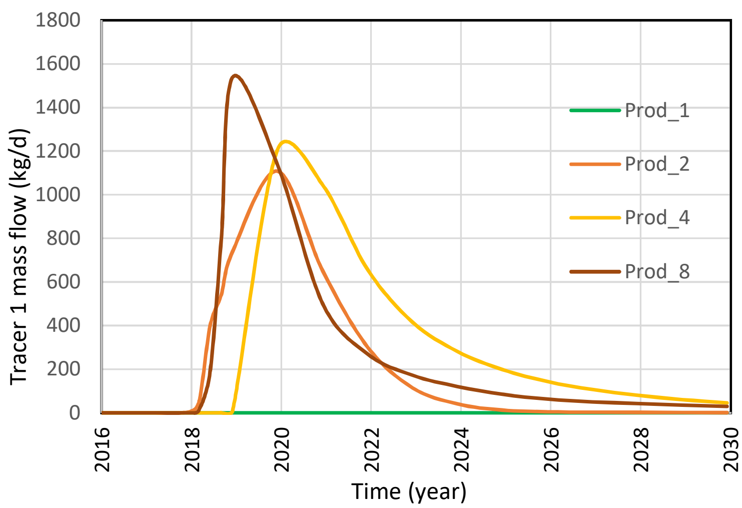

Figure 6. Tracer 1 mass flow per well

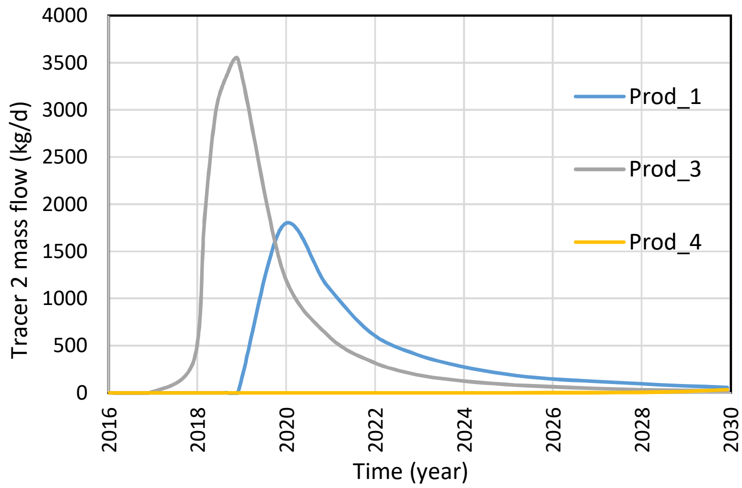

Figure 7. Tracer 2 mass flow per well

Response to the presence of high and low permeability zones. Two different zones were created in the reservoir, a high permeability zone (Figure 8) and a low permeability zone (Figure 12), so that their influence on each well could be analyzed.

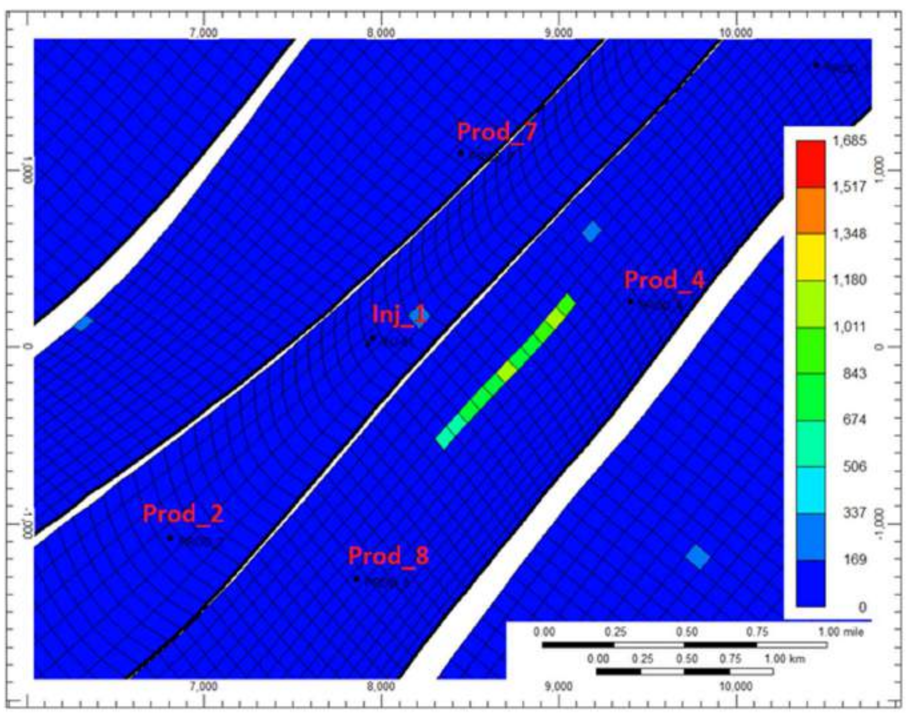

Figure 8. High permeability zone location

As Figure 9 shows, the presence of the high permeability zone did not have great influence on the production of the well 2, on the other hand, the wells 4 and 8 (Figure 10 and Figure 11 respectively) had greater tracer production. The greatest influence was noticed on the production of well 4, this fact can be associated with the location of the zone, which is closer to the well 4.

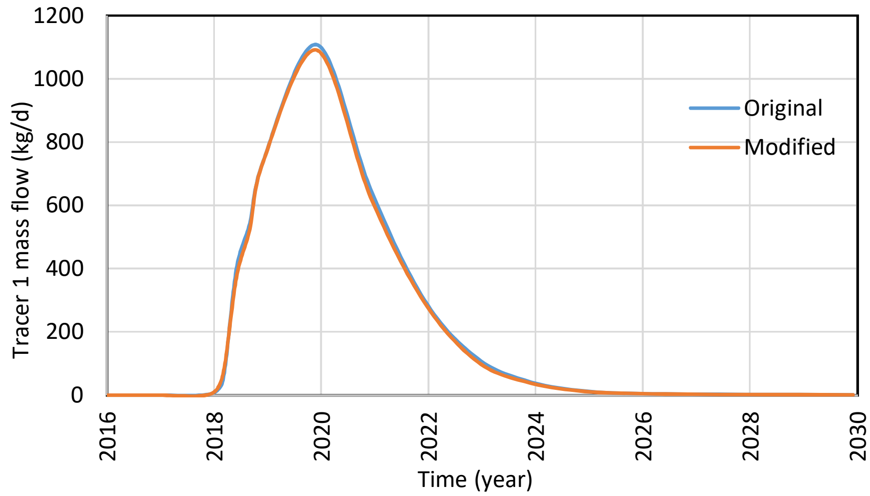

Figure 9. Production difference caused on producer 2

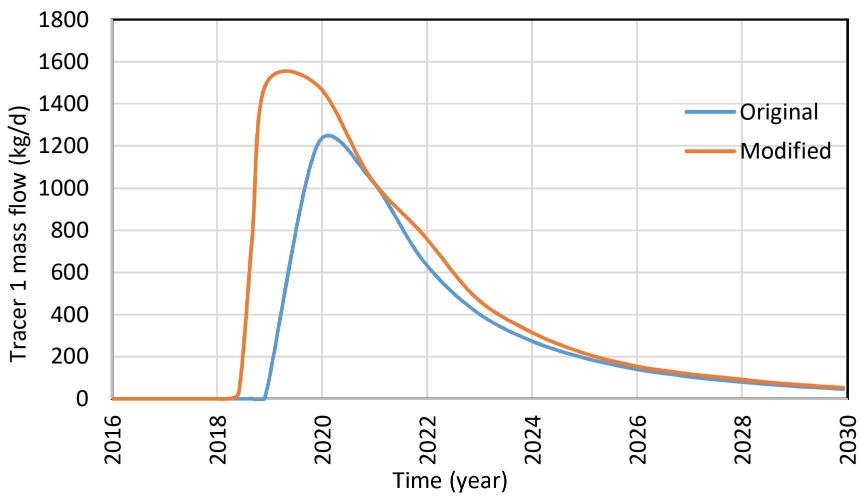

Figure 10. Production difference caused on producer 4

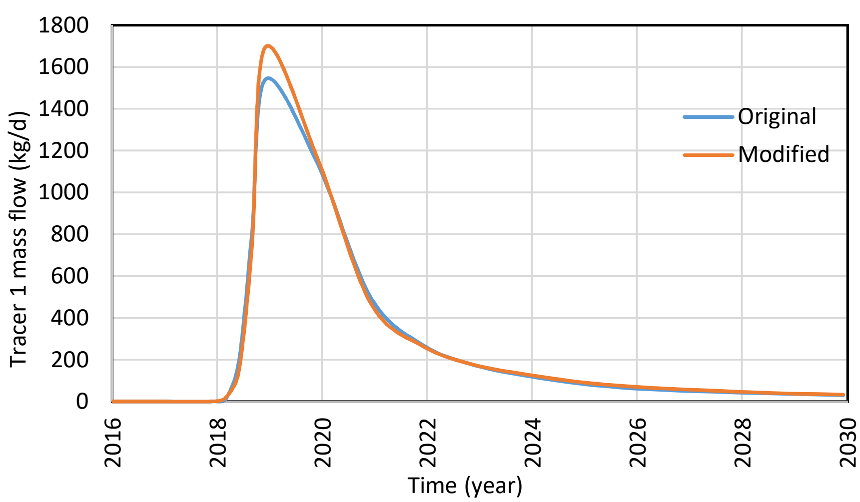

Figure 11. Production difference caused on producer 8

Figure 12 presents the low permeability zone, which is represented by the blue stripe in the center of the image. The presence of the low permeability zone increased the tracer production on the well 1 as shows Figure 13. This is because the low permeability zone guides part of the fluid that would be produced by the producer 3 to the producer 1. However, after the peak, the production is slightly lower than the one on the original model; this is because the low permeability zone behaves as a barrier that does not allow a full development of the flow lines, and prevents much of the pulse from reaching the lower fault, to be then conducted to the producer.

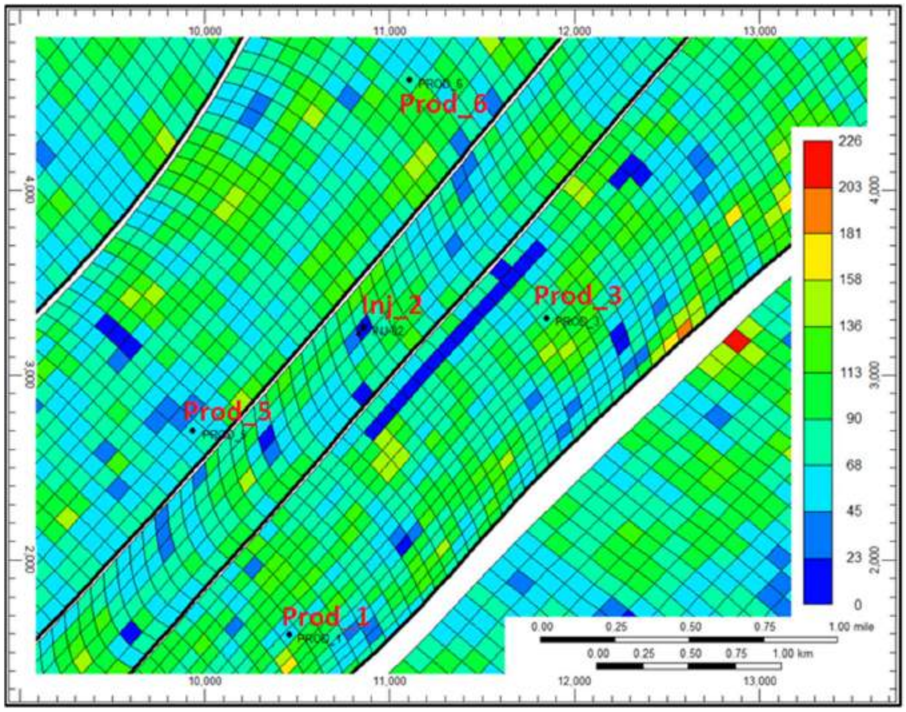

Figure 12. Low permeability zone location

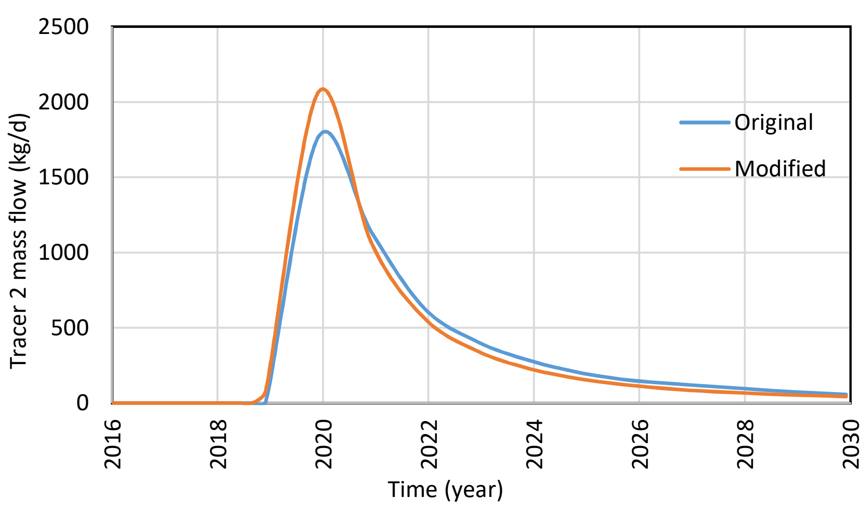

Figure 13. Production difference caused on producer 1

Figure 14 shows the production of tracer from the producer 3, it can be seen that the tracer breakthrough was delayed and that after 2019 the tracer production was greater than the production of the original model.

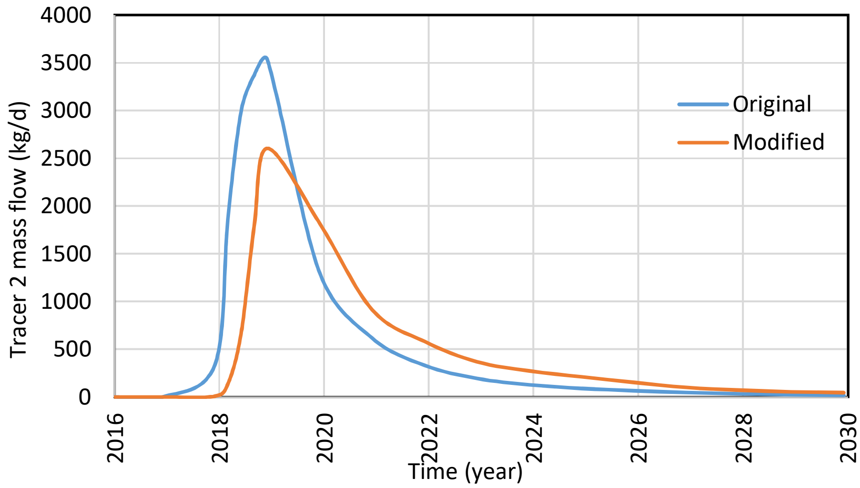

Figure 14. Production difference caused on producer 3

Response to contrasted permeability layering. As means of verifying if the simulations would be able to respond to permeability layering, the model was modified so that it would present a high contrast in layer's permeability. The modified model, Figure 15, shows 3 main permeability layers, the red layer permeability is 250 mD, the green, 125 mD, and the yellow, 5 mD. For this is a gas reservoir and this fluid has low motion restriction within the reservoir, the difference between the layers was accentuated.

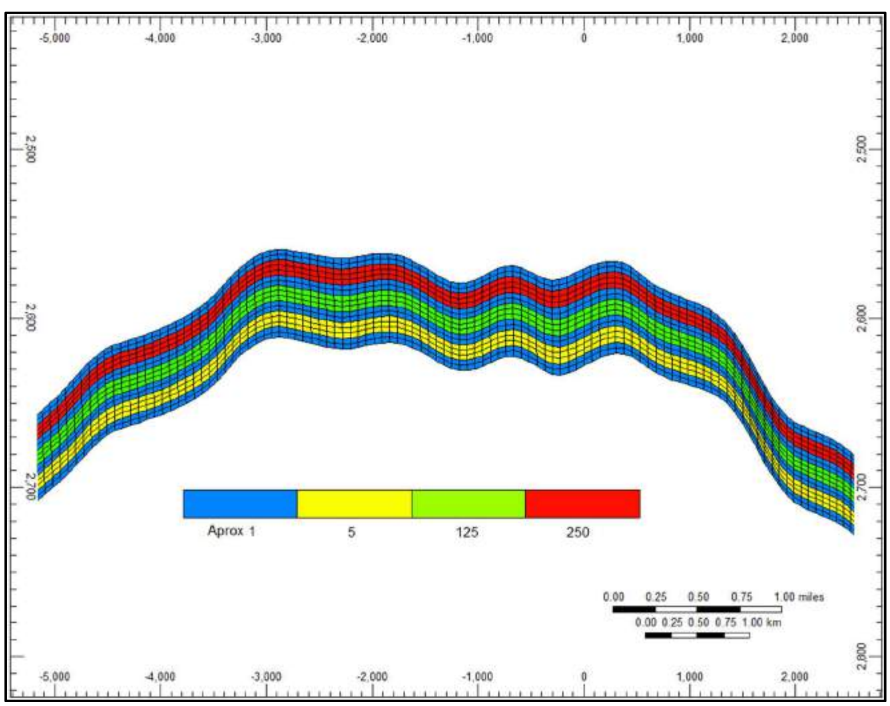

Figure 15. Permeability layers, JK cross-section

Figure 16 and Figure 17 show tracer 1 and tracer 2 production peaks. The peaks were circled in red for easier visualization in both figures, where three peaks can be seen; each of the peaks can be associated with one of the layers, the first peak to the permeability of 250 mD, the second peak to 125 mD and the third peak to 5 mD.

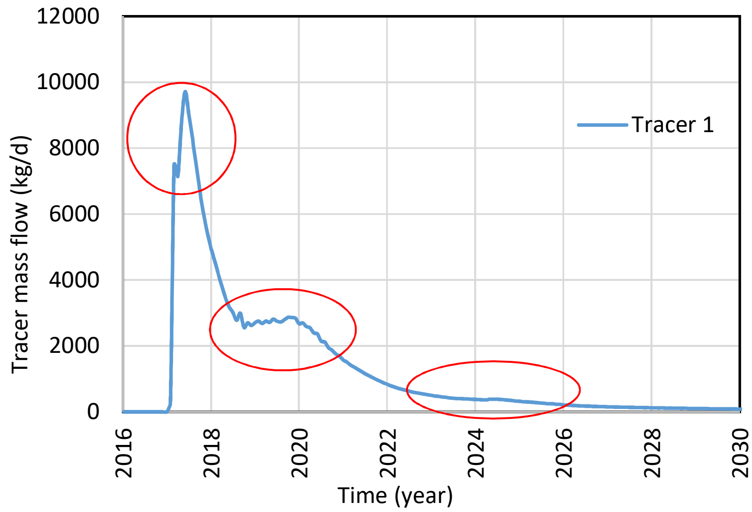

Figure 16. Tracer 1 peaks, field production

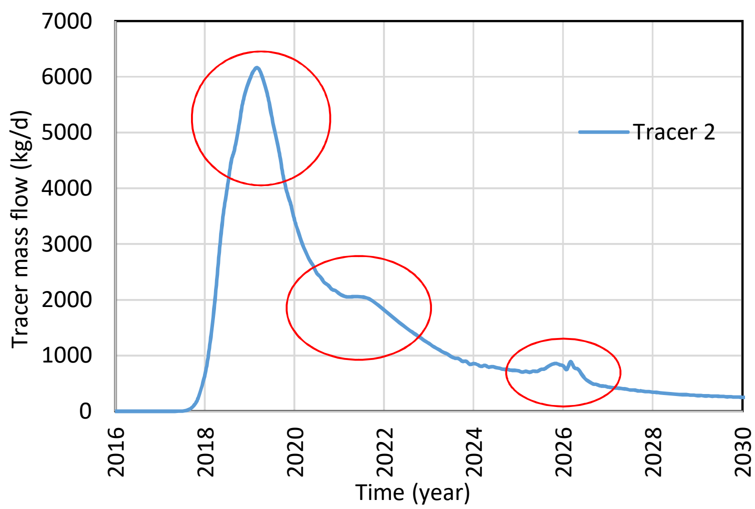

Figure 17. Tracer 2 peaks, field production

3.2. Results of tracing study on oil reservoir model

The simulations for the oil reservoir were made with the fluid presented in Table 2. The first study run in this model was injecting tracers along with CO_2 varying tracer injection form (pulse and continuous) and concentration (0.1, 1.0, 5.0 and 10.0 per cent); the goal of this is study is analyzing tracers' behavior curves in the oil reservoir and verifying the recovery factor achieved for each scenario.

Figure 18 and Figure 19 show tracer 1 and tracer 2 production, respectively, for the whole field with continuous injection. All of the curves were normalized for the concentration of 1.0% so that they would all fit the same graph and allow easier comparison. Figure 20 presents the oil recovery factor for each of the tracer injection concentrations, it can be noticed that the tracers breakthrough and oil recovery are pretty much the same for all of them. This behavior is desired, as the tracers should not influence the oil recovery.

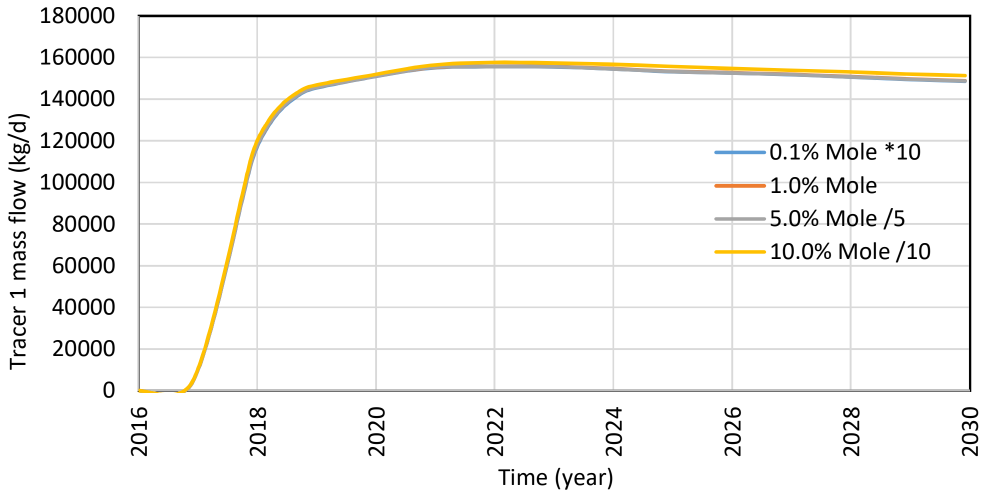

Figure 18. Tracer 1 field production, tracer continuous injection

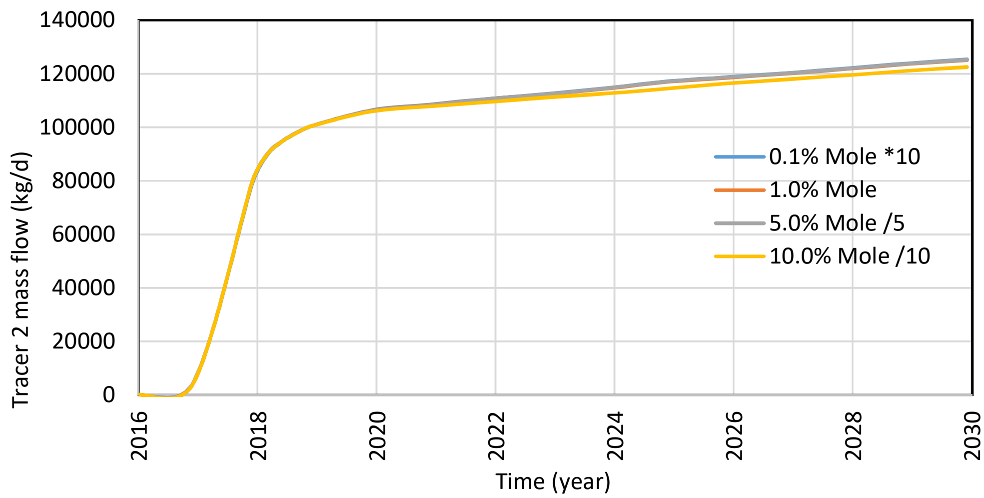

Figure 19. Tracer 2 field production, tracer continuous injection

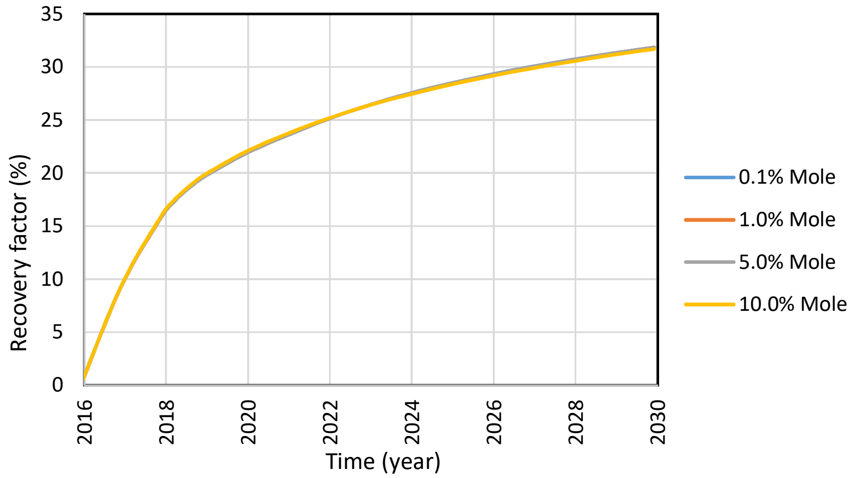

Figure 20. Recovery factor for CO_2 injection with continuous tracer injection

Figure 21 and Figure 22 show tracer 1 and tracer 2 production, respectively, for the whole field with pulse injection. Again the curves were normalized to 1.0% mole. As shown in these graphs, the tracers breakthrough, and tracers production peaks, main information obtained from Interwell tracer test were not influenced. Figure 23 presents the oil recovery factor achieved for each of the injection concentrations, again they were pretty much the same. When comparing both, oil recovery factor for continuous tracer injection and pulse tracer injection, they are very similar, which is also desired, as tracers are not supposed to influence hydrocarbon recovery.

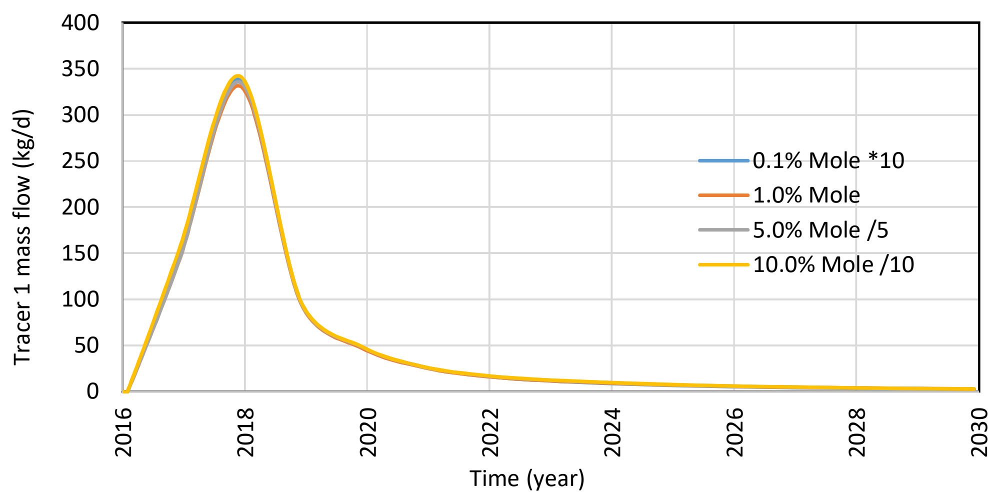

Figure 21. Tracer 1 field production, tracer pulse injection

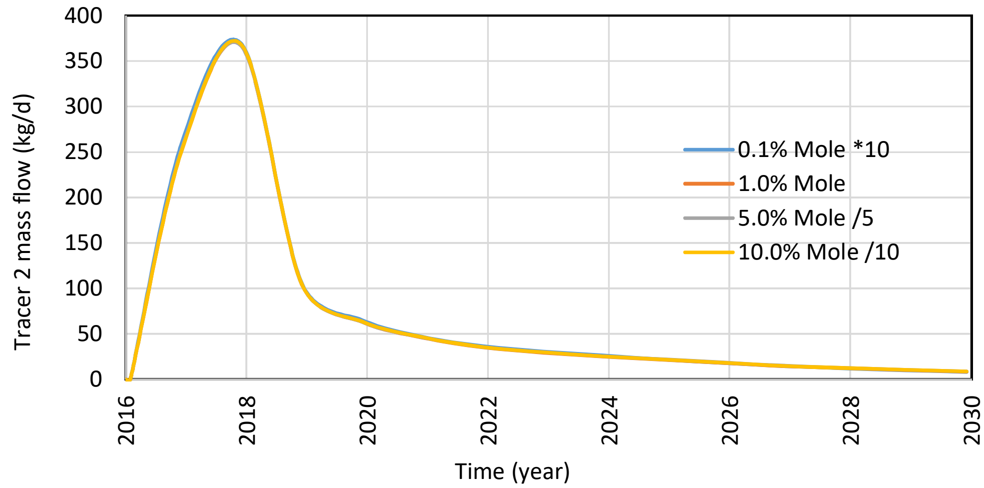

Figure 22. Tracer 2 field production, tracer pulse injection

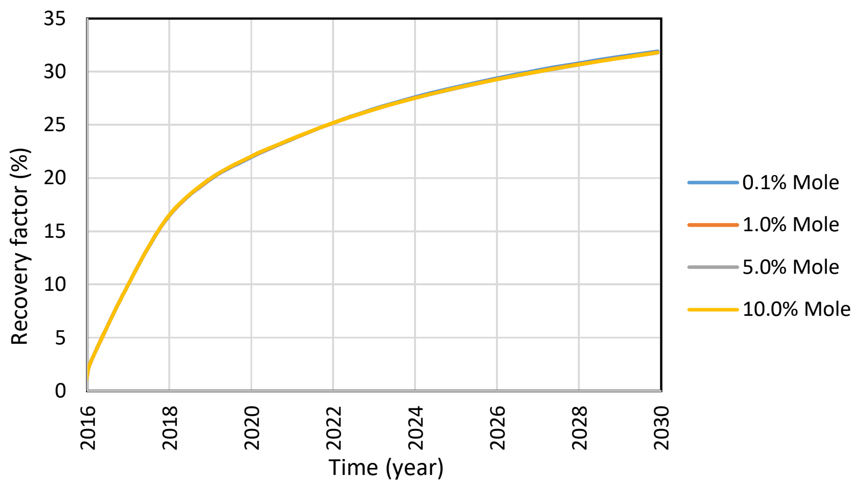

Figure 23. Recovery factor for CO2 injection with pulse tracer injection

WAG-CO_2 injection associated with tracers. Two main cases were simulated for choosing a better injection schedule when observing oil recovery only. The first case, A, with cycles of 6 months of water injection followed by 12 months of gas injection; the second case, B, with cycles of 12 months of water injection followed by 12 months of gas injection. This cycles duration consider the achieved oil recovery in MORAES & PEREIRA (2015).

Table 3 presents both simulated cases and their achieved oil recovery factor.

Table 3. Injection duration and WAG CO2 cycles recovery factor

	Case A		Case B	
	Water	Gas	Water	Gas
Injection duration (months)	6	12	12	12
Recovery factor (%)	28.04		25.34	

Because case A shows a greater recovery factor, it has been chosen for further studies. The injection and production curves from case A simulation are presented in Figure 24. All the curves were put in scale, so that they would fit the same graph. It is possible to observe that as the tracer flow rate increases, the decrease in oil production is minimized, that is, the oil flow rate is stabilized, indicating a connection between oil production peak and tracer production peak.

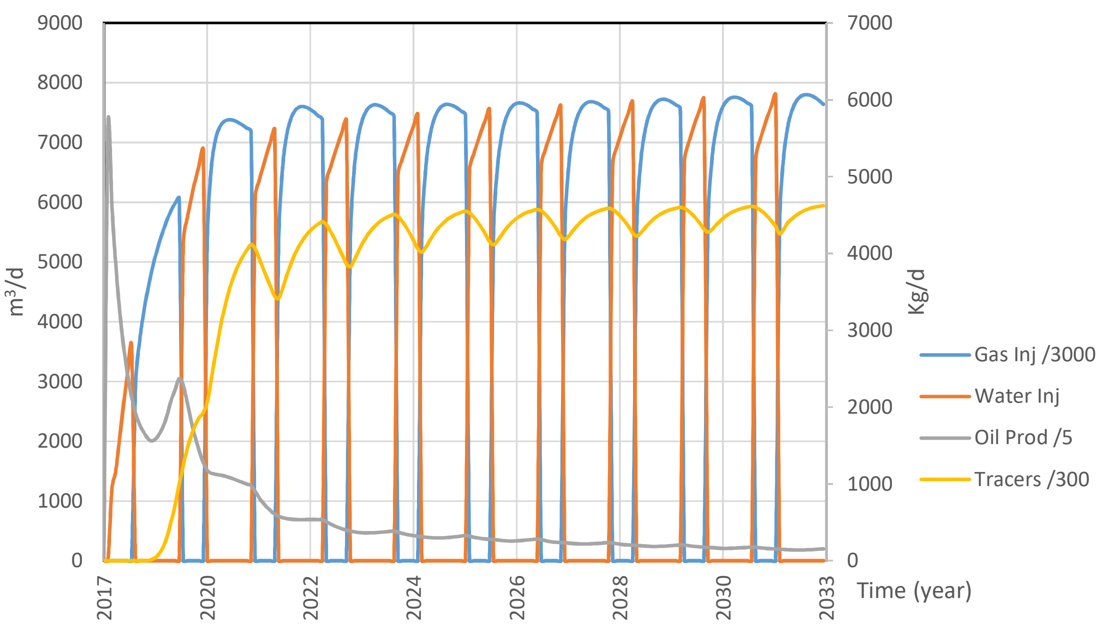

Figure 24. Injection curves (gas and water) and production curves (oil and tracers)

Reservoir pressure influence on the system. For comparison purposes only, a simulation in which the reservoir pressure was twice the original one was run, a study only possible in simulators. By increasing the reservoir pressure and consequently the injection pressure, reaching minimum miscibility pressure is expected to be favored.

Table 4 presents and compares tracers' injection and production for both, original reservoir pressure and doubled reservoir pressure. Under cumulative production, tracers on the gas phase and on the oil phase were separated. For both cases, tracers' production along with the oil phase is around 0.02%, while most of the injected tracers are produced along with the gas phase, that is, the tracer has a greater affinity with gas.

Table 4. Cumulative tracers' injection and production comparison

	Tracer	Cumulative Injection (10^9kg)	Cumulative Production Gas Phase (10^9 kg)	(%)	Oil Phase (10^5 kg)	(%)
Normal Pressure	1	3.84	3.46	90.12	7.76	0.02
	2	3.21	2.72	84.82	6.31	0.02
Doubled Pressure	1	4.52	3.69	81.58	1.34	0.03
	2	3.75	2.82	75.13	7.19	0.02

Table 5 presents the masses of tracers retained in the reservoir. When the reservoir pressure is doubled the retained amount increases. This increment is related to the miscibility, as it causes the tracers to better mix with oil, thus mixing with the contacted remaining oil.

Table 5. Tracers retention in the reservoir

	Tracer	Cumulative Production (%)	(10^9 kg)	Retained Tracer (%)	(10^8 kg)
Normal Pressure	1	90.14	3.46	9.86	3.79
	2	84.84	2.72	15.16	4.86
Doubled Pressure	1	81.61	3.69	18.39	8.31
	2	75.15	2.82	24.85	9.33

Production strategy analysis. Because of the uncertainties, the risks associated with the development of the reservoir sectors 1 and 4 and graphic responses shown in Figure 25 and Figure 26, the location of wells were altered so that sectors 2 and 3, which are known, could be prioritized. The circles on Figure 25 and Figure 26 show areas that are influenced by the injection, but are not produced in the original model. The white circles are where to locate wells.

The new positioning of the wells is presented in Figure 27. The modifications are the removal of the three production wells from sector 1, allocation of two production wells on sector 2, in each of the white circle areas in Figure 25 and Figure 26. The yellow circle on Figure 26 shows an area that is influenced by both injectors. For this, the producer 5 was allocated in this area as seen in Figure 27.

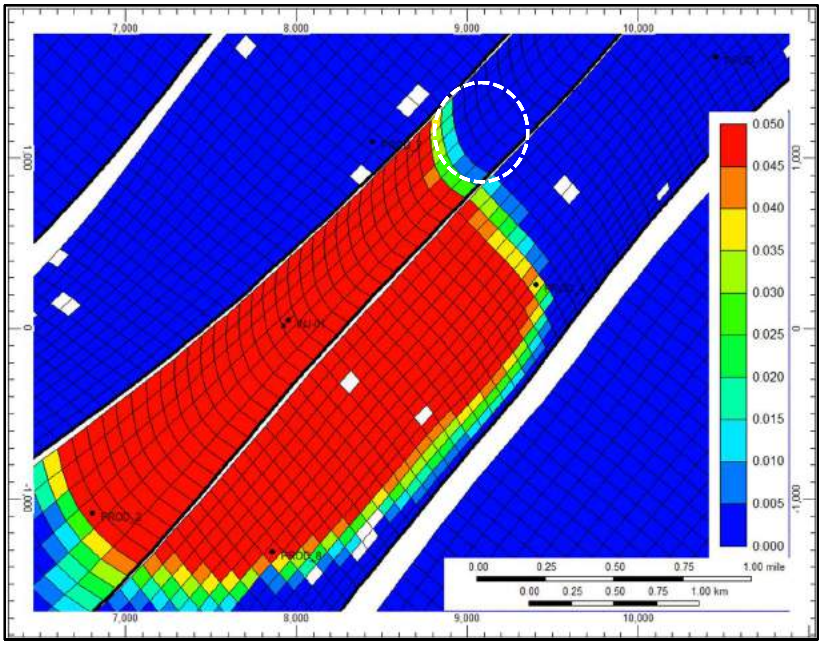

Figure 25. Tracer 1 global molar fraction (injector 1 influence)

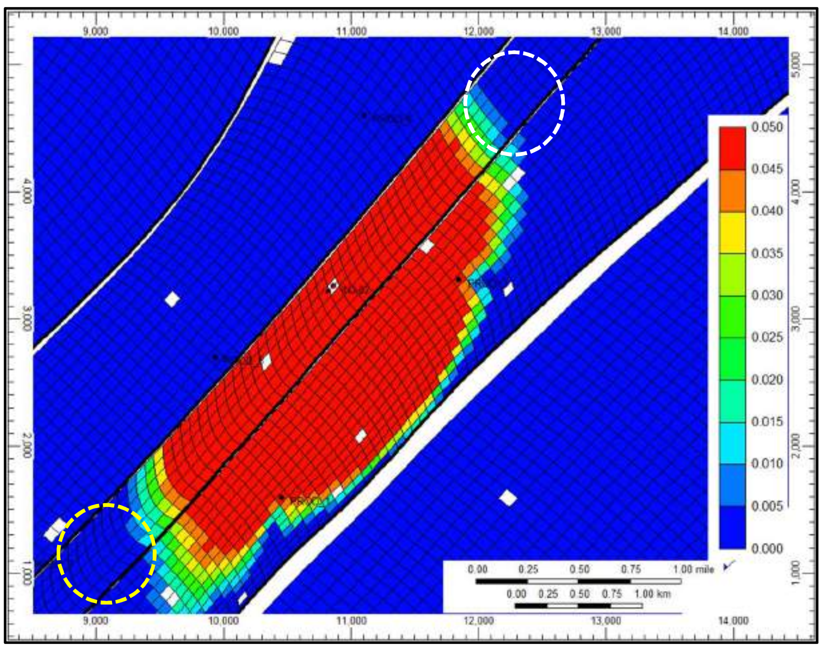

Figure 26. Tracer 2 global molar fraction (injector 2 influence)

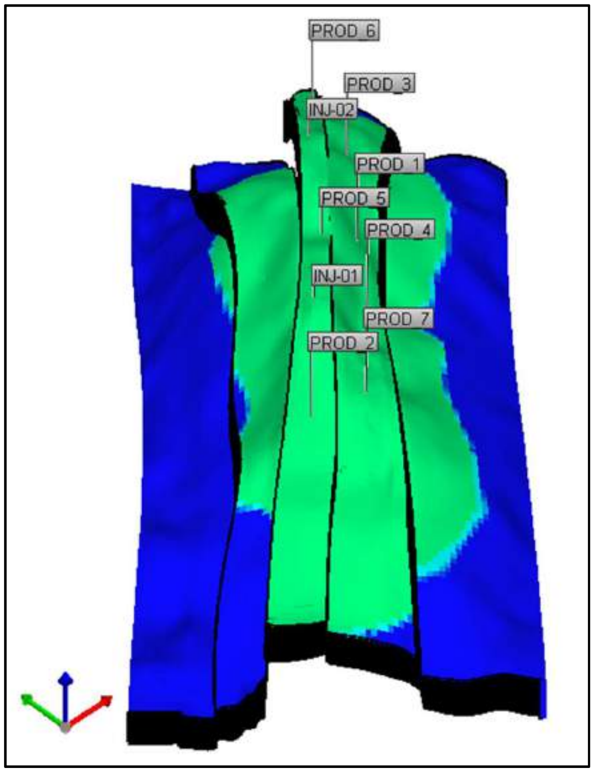

Figure 27. Wells strategic repositioning

Table 6 presents the production from both scenarios (original and new strategy) divided into sectors. The recovery factor of the sector 2 was practically tripled, on the other hand, sector's 3 recovery factor was decreased in 8%; this can be attributed to the competition between the wells for the influence of the injector wells. This means that an optimization study should be developed to avoid such competition.

Table 6. Production data from compared scenarios

Original oil in place, OOIP; Cumulative production, Np e Recovery factor, FR					
		Original		New Strategy	
	OOIP (m^3)	Np (m^3)	FR (%)	Np (m^3)	FR (%)
Sector 1	$1.92*10^7$	$3.43*10^6$	17.89	0	0
Sector 2	$1.95*10^7$	$2.99*10^6$	15.33	$8.86*10^6$	45.42
Sector 3	$3.25*10^7$	$1.61*10^7$	49.51	$1.34*10^7$	41.23
Production Zone (sector 2 +3)	$5.2*10^7$	$1.91*10^7$	36.68	$2.22*10^7$	42.80
Field	$8.02*10^7$	$2.25*10^7$	28.04	$2.22*10^7$	27.74

Figure 28 presents the cumulative oil production for both cases from Table 6. Figure 29 presents the production curves for oil, gas, and water.

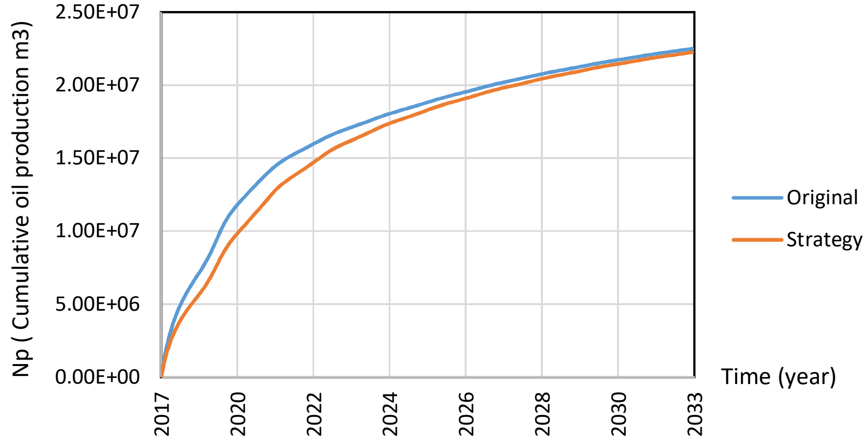

Figure 28. Cumulative oil production curves

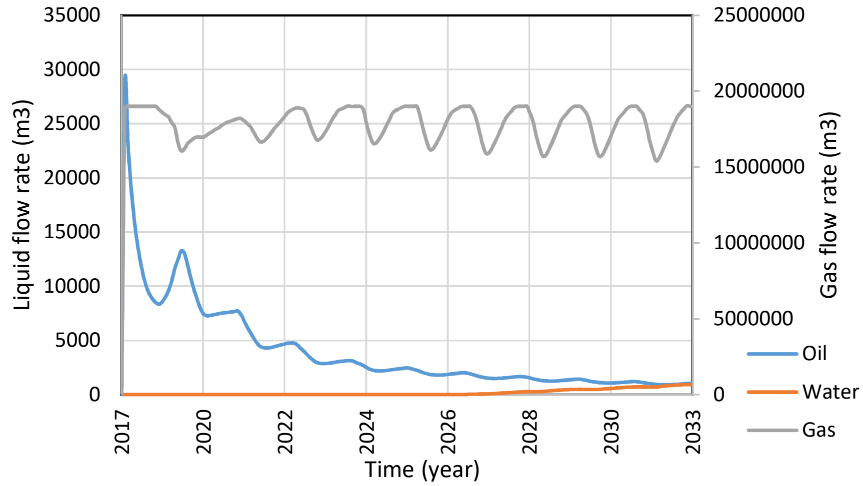

Figure 29.Oil, water and gas production curves

Net present value (NPV) analysis. For a simplified NPV calculation, the premise values in Table 7 and Excel® were used.

Table 7. Base values for NPV calculation

Project's cash flow	
Oil price [US$/bbl]	50
Gas price [US$/m^3]	0.3
Taxation [%]	40%
Extraction cost [US$/bbl]	15
Water treatment cost [US$/bbl]	5
Water injection cost [US$/bbl]	1
Annual interest rate [%]	10%
Well price [MMUS$]	60
Production Unit	1000
Interventions [MMUS$]	2.5
Operational Costs [MMUS$]	50
Collection Investment	400
Abandoning Cost [MMUS$]	360

The calculated NPV for the original scenario is 5469.0 MMUS$, while the NPV for the new production strategy is 5790.7 MMUS$, that is, the new strategy outperforms the original one in 321.7 MMUS$, indicating that the project is feasible and that this modification in the original production pattern increased the project's financial return. It also adds to the fact that the risks associated with the production of the adjacent area, the one with little information available, are avoided.

4. CONCLUSIONS

Tracers can be used to aid, in many ways, the production of hydrocarbons in a field making it possible to understand the injected fluids flow paths and adding information to the development of the field.

The present work contributes to the understanding of a reservoir production associated with tracer injection and production response curves. The simulation and study of tracer injection were possible through incorporation of tracer components to the original gas and oil models.

The simulations run in the gas reservoir made it possible to minimize tracer partition into the oil phase. Studies of discontinuities (high and low permeability zones and contrasted permeability layering) responses were as expected.

The simulations run in the oil reservoir showed that the concentration of tracers would not influence the oil recovery factor, which is desired, as tracers should not affect the production of hydrocarbons. The study of WAG-CO_2 injection along with tracer related the production of tracers with that of oil. Studying the reservoir pressure evidenced the effect of miscibility as a greater retention of tracer could be noticed in the oil phase.

Studying the spreading behavior of the tracers indicated areas where new wells could be allocated in order to increase oil recovery, allowing production strategy reassessment and quantification of the economic gain obtained with the modification of strategy. The possible economic gain when comparing both strategies is 321.0 MMUS$.

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