TECHNICAL-ECONOMIC EVALUATION OF CONTINUOUS CO2 REINJECTION, CONTINUOUS WATER INJECTION AND WATER ALTERNATING GAS (WAG) INJECTION IN RESERVOIRS CONTAINING CO_2

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Abstract. *Oil reservoirs that contain high carbon dioxide (CO_2) concentrations associated with produced gas are excellent candidates for implementing CO_2 injection techniques as secondary recovery method. It allows the recovery of residual oil combined with environmental benefits by reinjecting the CO_2 production. This study evaluates the efficiency of the WAG technique compared with continuous fluid injection. The proposed reservoir model consists of a rectangular box geometry with a quarter of a five-spot configuration with two wells – one injector and one producer, diagonally opposite from each other. Simulations were made to compare the total volume of oil recovered in four different secondary recovery injection scenarios: 1) continuous water injection, 2) continuous gas injection, 3) WAG injection with cycles of 2 years and 4) WAG injection with cycles of 4 years. For each scenario, the reservoir would produce for two years, and then would start its secondary recovery stage. The parameters analyzed were the gas injection rate and the water injection rate, in order to evaluate how they would affect the production rate. Both parameters were optimized using DECE method, available in the CMG suite, to reach the maximum net present value (NPV) in each case. The reservoir model was built with similar fluid characteristics of the pre-salt in the Santos basin – a light oil with CO2 concentrations of up to 30%.*

Keywords: *Enhanced oil recovery, WAG, NPV, CO_2, EOR.*

1. INTRODUCTION

Oil is still the major non-renewable energy source in Brazil and one of the main sources in the world, due to the large variety of products that are derived from its processing.

The lighter the oil, the bigger the amount of noble items derived from its refining, and therefore the higher added value to its products. Petrobras announced the discovery of the Lula field in 2006, with an extraordinary amount of light oil in the pre-salt layer (DINIZ, 2015). These reservoirs contain a large volume of associated gas with an average CO_2 molar concentration of 20% to 30%, and in some cases the concentration can go up to 80%. Although very promising, the discovery also brings a very challenging scenario in terms of new technologies to develop the wells, reservoirs and fields. On top of it, choosing the best production strategy ensures that the reservoir full potential would be reached, even when the reservoir enters its depletive phase.

During the well productive life, there is a drop in the production rate due to the reduction of the reservoir initial energy. One of the main steps of reservoir management is to avoid that this initial energy reaches a lower limit by using secondary recovery methods to extend the production capacity. Enhanced Oil Recovery (EOR) methods help to produce part of the irreducible oil, adding an extra portion of the residual oil to the total production. These recovery methods have distinct characteristics among them and each one causes a consequence in the reservoir, like changing the capillary pressure, mobility ratio, wettability, interfacial tension, viscosity reduction and sweep correction.

The main motivations to perform EOR studies in reservoirs containing carbon dioxide (CO_2) were the presence of CO_2 as a contaminant combined with a high GOR (gas-oil ratio) in the reservoir fluid. The best strategy for EOR in these fields would be to re-use the resources available as seawater and the produced gas, making it highly attractive for water alternating gas (WAG) technique. Another motivation to combine different methods is driven by some undesired results of the continuous CO_2 injection such as, for instance, pipe and equipment corrosion, which demands special construction, and the organic material (asphaltene) deposition. The last one being responsible for the pore size reduction in the reservoir and permeability variation, resulting in a reduction of the oil recovery factor.

WAG technique is used as an alternative for recycling the abundant resources available offshore and as an optimization strategy for EOR in these kind of reservoirs. The conventional water and gas injection methods (continuous) tend to leave some amount of residual oil, around 20 to 30%, on the other hand WAG technique can reach an efficiency of 90% when used on a five-spot grid (MATTE, 2011).

In this particular study, the idea is to make evident the better performance of the WAG technique compared to the continuous single fluid injection (CO_2 or water) and make an analysis of the economic feasibility for a reservoir with a considerable amount of associated CO_2. For that, the scenarios will be simulated using the GEM module (compositional simulator) available in the software suite from Computer Modelling Group (CMG). The reservoir to be analyzed will be homogeneous and anisotropic modeled from a tridimensional Cartesian grid. The injection-production grid will be designed as a quarter of a five-spot well configuration.

2. METHODOLOGY

This paper consists in simulating four different cases of secondary oil recovery: continuous gas injection (with reinjection of the produced gas), continuous water injection and WAG injection, the last one with two distinct WAG cycles, two and four years. Besides these scenarios, it is also simulated the reservoir production with no secondary recovery method, contemplating only its primary drive mechanisms. The simulations were done utilizing the GEM (Generalized Equation of State Model Compositional Reservoir Simulator) Module CMG suite. This software is a compositional simulator based on the state equation to model multicomponent flow, miscible and immiscible processes in any type of reservoir including non-conventional ones where the fluid composition and its interactions have an important role in the recovery method comprehension.

From the above simulations mentioned, it was analyzed each enhanced recovery method performance, through the recovered oil volume comparison among the cases.

Once studied and evaluated the technique, it was done an economic analysis through an net present value (NPV) calculation of each scenario, aiming the feasibility determination.

The authors also ran optimization studies using the CMOST module of the CMG suite. CMOST is an integrated analysis tool used to change injection parameters of the reservoir in order to achieve the best NPV output.

Figure 1 shows the proposed workflow for the experiment.

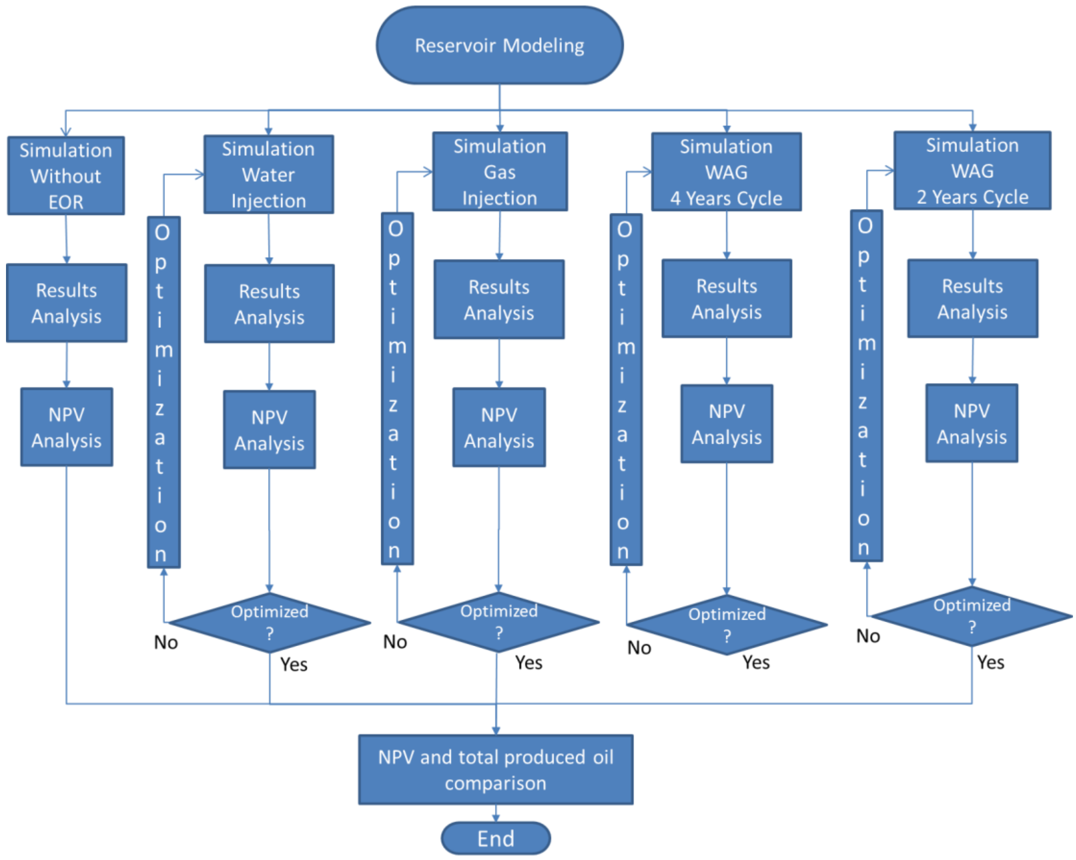

Figura 1. Proposed workflow

3. CASE STUDIES

The simulation details and modeling are mentioned below.

3.1 Simulation Model

A 5250 ft x 5250 ft x 197 ft tridimentional cartesian grid was designed and divided in 21 x 21 x 10 blocks, in each respective direction. The 10 blocks in "k" direction have variable thickness, in order to try to simulate a variation in the reservoir vertical permeability, as shown in Figure 2.

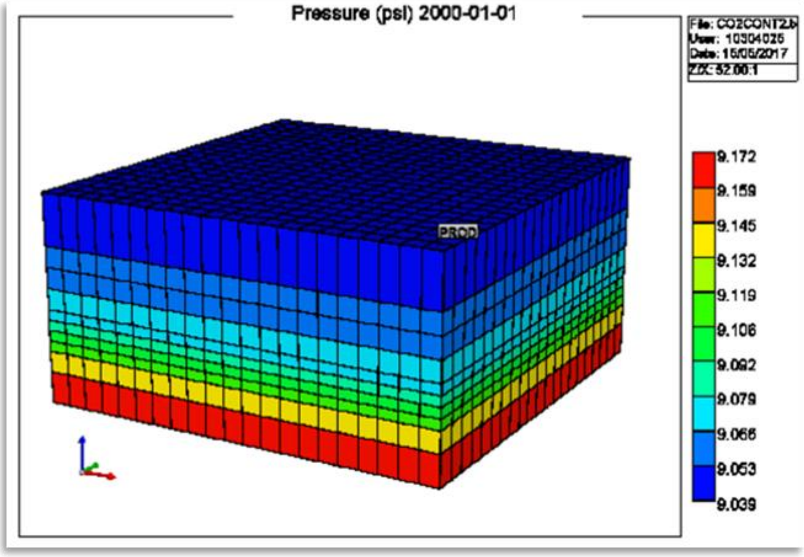

Figure 2. Simulated reservoir model.

The reservoir was modeled with fluid characteristics similar to the ones usually found in Santos pre-salt basin. "k" direction – vertical – was split in layers so different properties of the reservoir could be attributed aiming an anisotropic model. In this case, it was considered 10 layers of variable thickness as shown in Table 1:

Table 1. Layer Thickness in "k" direction.

Thickness [ft]	Number of blocks
50	1
20	3
10	4
20	1
30	1

It was considered a pressure gradient of 0.78 psi/ft to simulate a pressure profile compatible with the ones found in Santos basin.

3.2 Rock Properties

It was considered an anisotropic porous bulk where the permeability changes in all three directions i, j e k, in such a way that the vector $\vec{k}$ values are distributed as the figures and tables below.

Table 2. Permeability vector values.

Permeability [md]			Block
i	j	k	
300	300	50	1
500	500	60	2
300	300	60	3
200	200	50	4
50	50	20	5
20	20	10	6
30	30	10	7
50	50	10	8
200	200	30	9
150	150	20	10

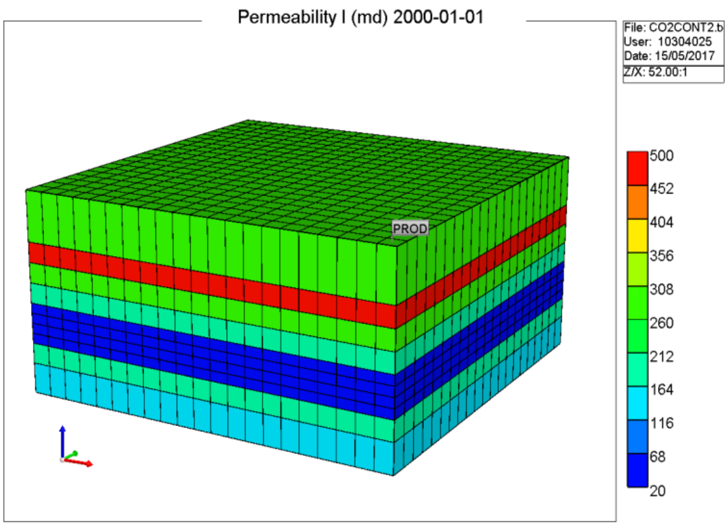

Figure 2. Permeability distribution – "*i*" and "*j*" direction ($k_i = k_j$).

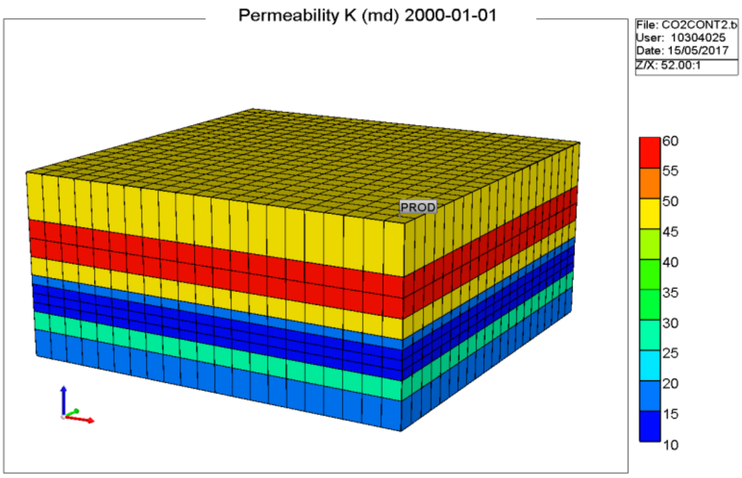

Figure 3. Permeability distribution – "*k*" direction.

It was adopted a homogeneous distribution of 30% porosity for the whole reservoir.

3.3 Operational Parameters (Initial Conditions)

The operational parameters used as input data in the simulations are presented in Table 3. The same initial parameters were considered for all four cases studies. The injection rates were later optimized through CMOST.

Table 3. Initial parameters.

Injection rate		Production cut-off	
Water (bbl/d)	Gas (m^3/d)	Water Cut (%)	RGO (m^3std/m^3std)
30.000	453.000	83,3	1.700

3.4 Fluid Composition

The fluid composition used is described in Table 4 in fractions of pseudo components in the GEM module. To describe the fluid thermodynamic interactions, it was chosen the Peng-Robinson model.

Table 4. Fluid composition.

Component	Fraction
C1	0,50
C3	0,08
C6	0,05
C10	0,10
C15	0,02
C20	0,03
CO_2	0,22

3.5 Relative Permeability

The relative permeability profiles related to water, oil and gas, are presented in the graphics below as a function of water saturation.

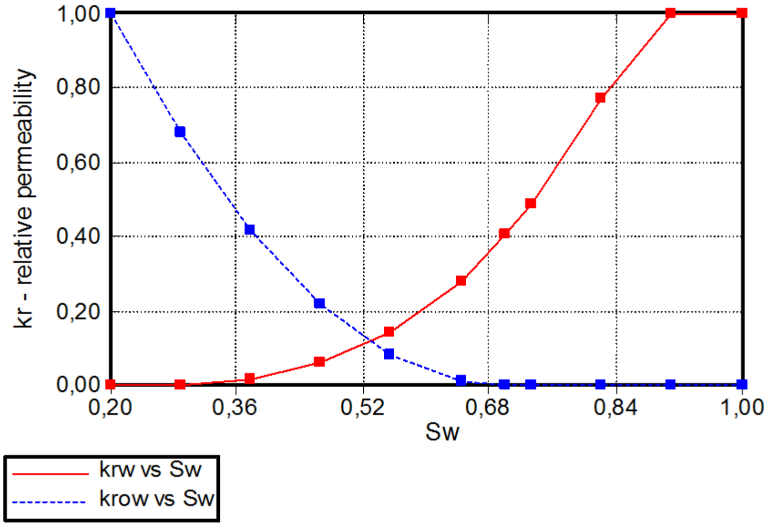

Figure 4. Relative Permeability of oil and water versus water saturation.

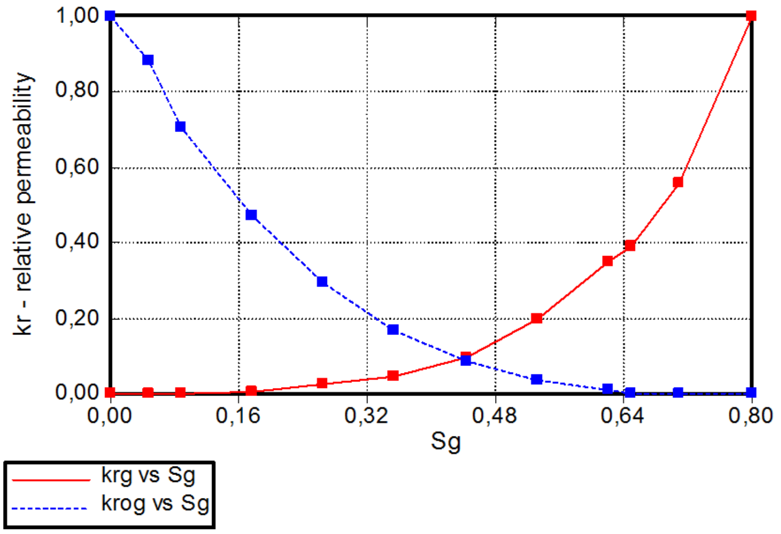

Figure 5. Relative Permeability of gas and oil versus gas saturation.

3.6 Reservoir Drive Mechanisms

Five cases were simulated with the first one considering only the primary drives of the reservoir, with no additional recovery method. Two more cases with single fluid injection were simulated for purposes of comparison with WAG effectiveness: continuous water injection and continuous gas injection (with produced gas reinjection). Finally, as main objective of this paper, two scenarios of WAG injection with different time cycles (4 and 2 years) were simulated. In all cases, with any secondary recovery method, the injection process started only

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after the second year of primary production. In the WAG scenarios, it was chosen to start with the gas injection cycle. The details of each case are described in the Table 5.

The injection grid used was the same for all cases and represents a quarter of a five-spot configuration, that is, a producer well and an injection well in diagonally opposite corners of the tridimensional Cartesian grid.

Table 5. Simulation scenarios.

Scenarios	Recovery Method	Injection Duration (Years)	Number of Cycles
1	Primary drive mechanisms	-	-
2	Continous water injection	28	-
3	Continous gas injection	28	-
4	WAG 4 years cycle	28	7
5	WAG 2 years cycle	28	14

4. RESULTS AND DISCUSSIONS

The results were obtained after an optimization process of the input parameters (water injection rate and gas injection rate) in CMOST platform through the DECE method, running 100 experiments for each case. The optimization target was the best NPV value for the designed scenarios. The curves below present the results of the production rates for oil, water and gas, also the injection rates for water and gas, when applicable.

4.1 Production with Primary Drive Mechanisms

In this scenario, without any type of secondary recovery, the NPV was calculated in US$ 55.40 million. In Figure 6, one can observe the estimated production and also its end after 17 years due to the GOR cut off being reached. The drop in the reservoir pressure due to the production, without any secondary recovery method which would help keep the pressure level, results in a pre-mature release of the associated gas in the crude oil.

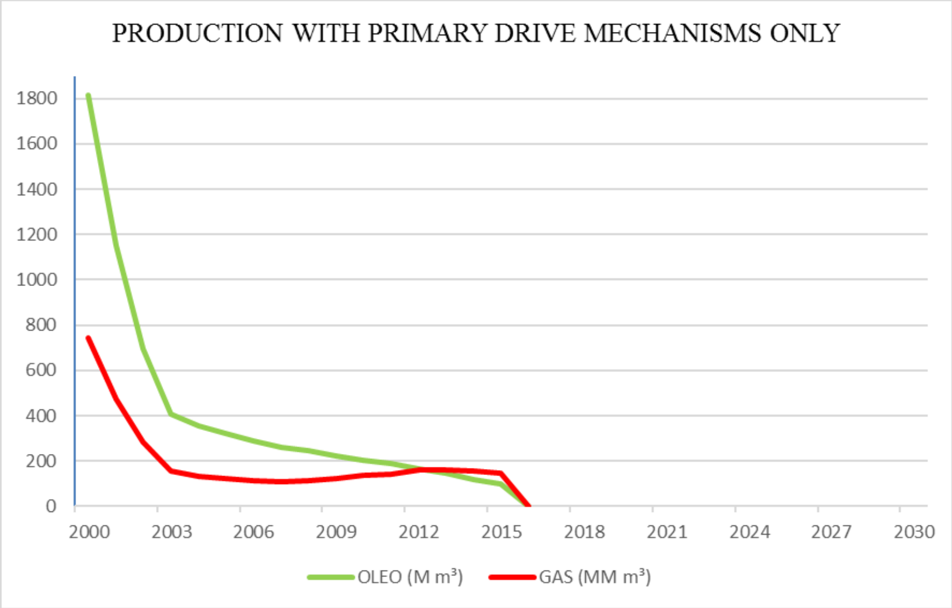

Figure 6. Production with primary drive mechanisms.

4.2 Production with Continuous Water Injection

In this scenario, the continuous water injection started in the third year of production. The NPV obtained in this case was US$ 155.10 million. In Figure 7, one can observe that the maintenance of reservoir pressure in higher levels helps to extend the productivity and the life cycle of the reservoir. It will result in bigger volumes of recovered oil and also a higher NPV when compared to the previous case where no injection was applied.

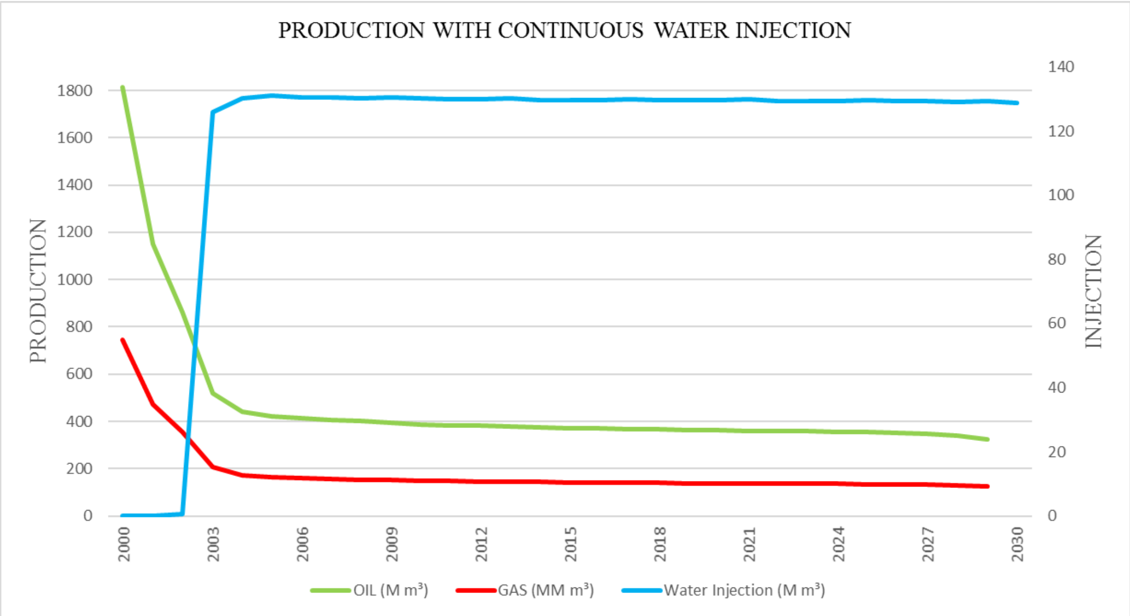

Figure 7. Production with continuous water injection.

4.3 Production with Continuous Gas Injection

As previous case showed, the secondary recovery started in the third year of production, but in this case with continuous gas injection. One can observe the oil production dropping after 16 years at the same time the gas production increases. If the well production were extended for more than the original 30 years predicted, the injected gas reaching the producer well would end activating the GOR cut-off, shutting the well production, as seen in the scenario without secondary recovery. The calculated NPV for this scenario is US$ 92.22 million.

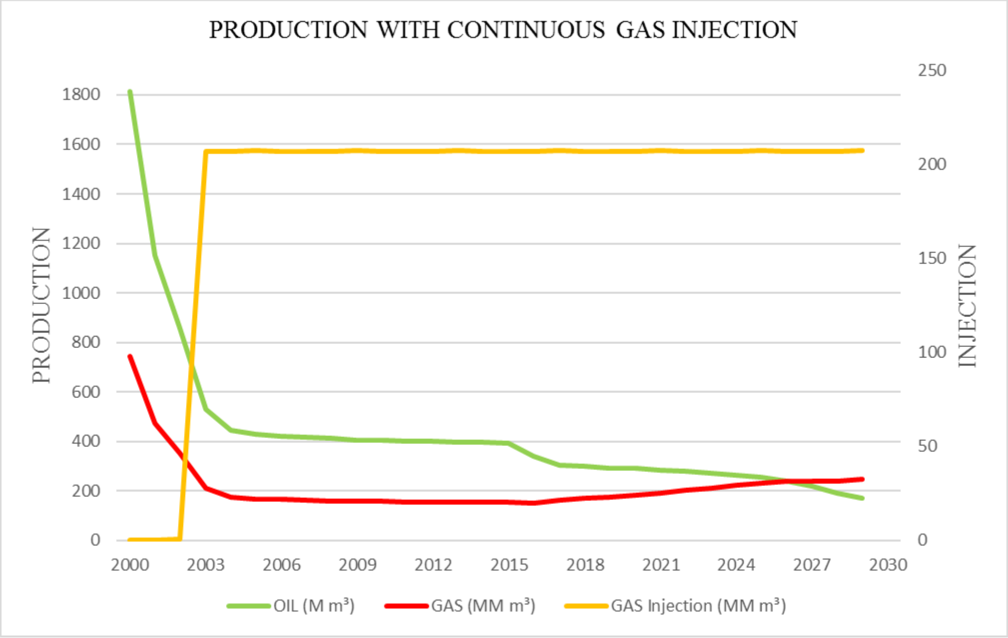

Figure 8. Production with continuous gas injection.

4.4 Production with WAG injection – 4 Years Cycle

The production for the first case with WAG injection was simulated with an alternated cycle of 4 years, with 2 years of gas injection and 2 year of water injection. For this scenario, it was obtained the highest NPV of all the scenarios, totalizing US$ 189.80 million.

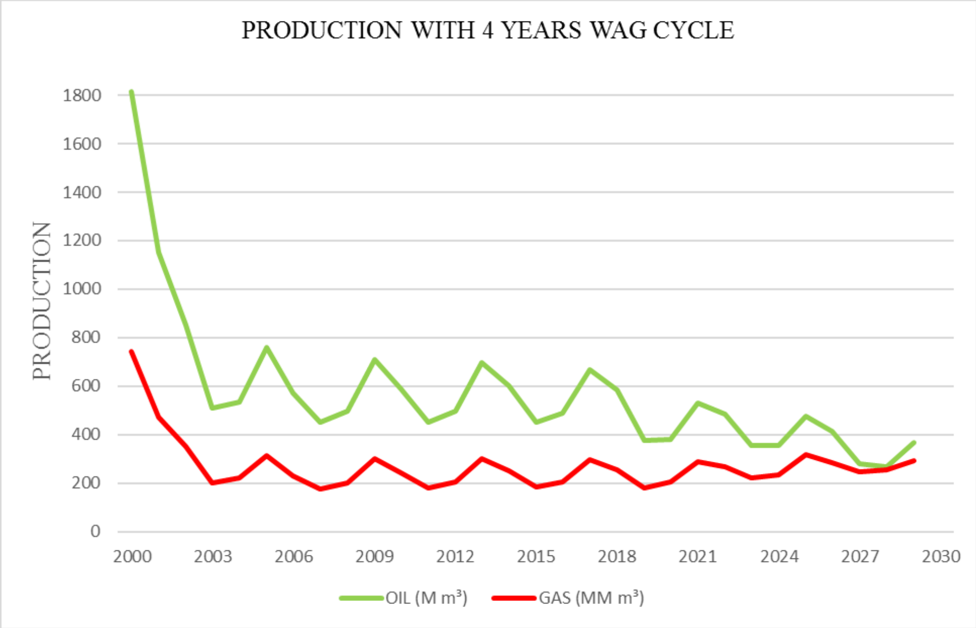

Figure 9. Production with WAG injection – 4 years cycle.

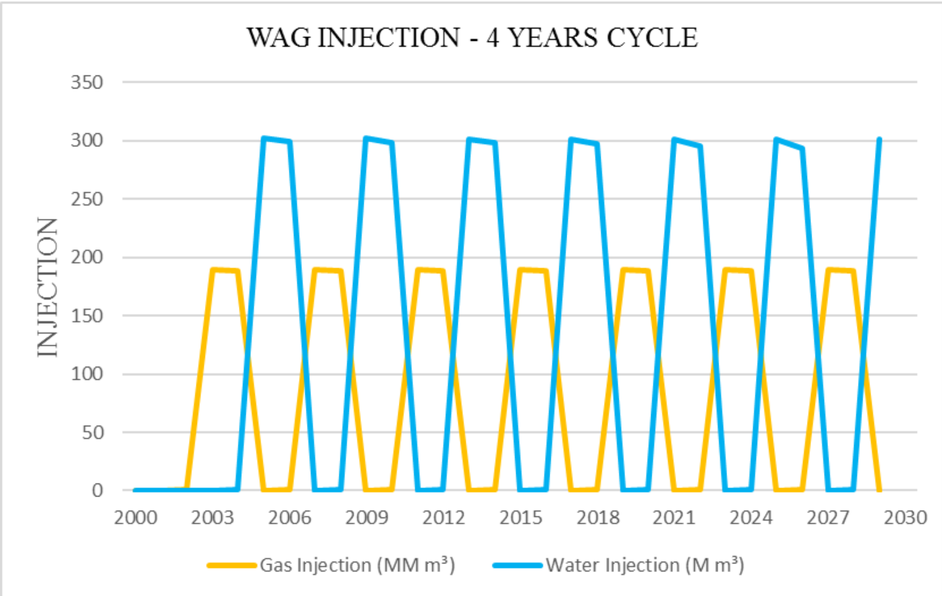

Figure 10. WAG injection – 4 years cycle.

4.5 WAG Injection – 2 Years Cycle

For the WAG injection with 2 years cycle, the NPV obtained was US$ 170.18 million. The results showed a more constant behavior of production rate compared to the previous case.

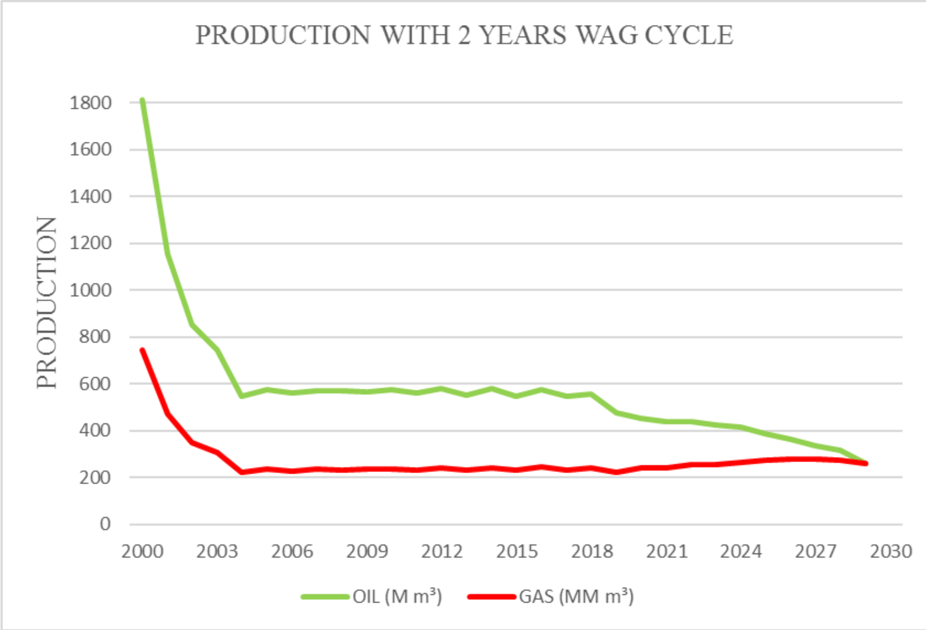

Figure 11. Production with WAG injection – 2 years cycle.

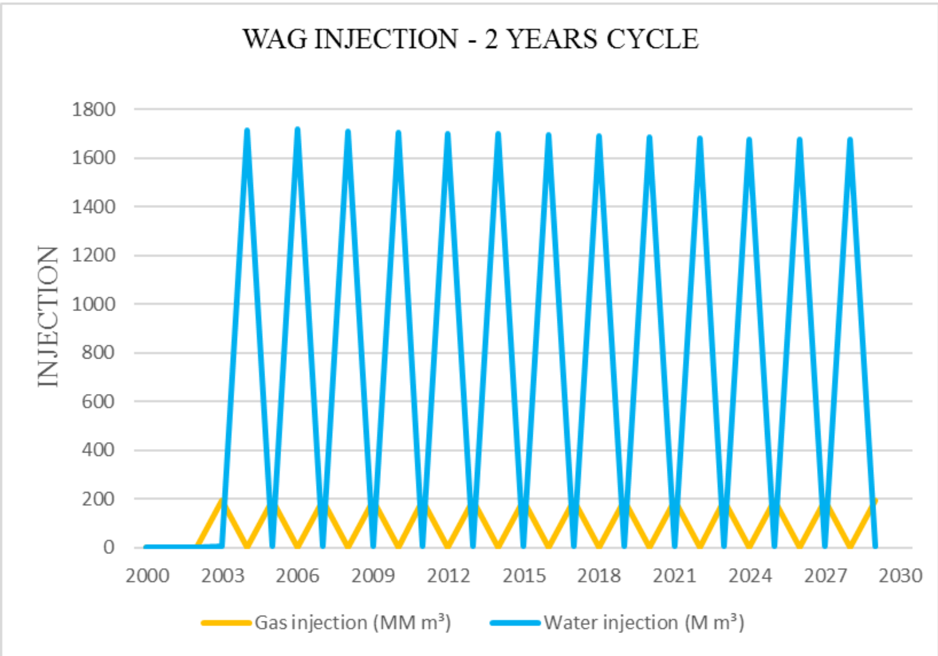

Figure 12. WAG injection – 2 years cycle.

4.6 Comparison Between Simulated Scenarios

In Figure 13, one can observe the comparison between the cumulative oil produced for each one of the 5 scenarios. It is clear the better performance of the cases where the secondary recovery method was used. As expected, the continuous gas injection showed better results in the first years of injection when compared to the continuous water injection technique.

However, in the long term, the continuous gas injection loses efficiency, being surpassed by the continuous water injection method in terms of volume of oil recovered.

Unlike what occurred in the continuous gas injection case when the injected gas was detected in the producer well, for the continuous water injection method no injected water was produced with the recovered oil. This behavior can be explained due to the homogeneity of the permeability and porosity used in this study.

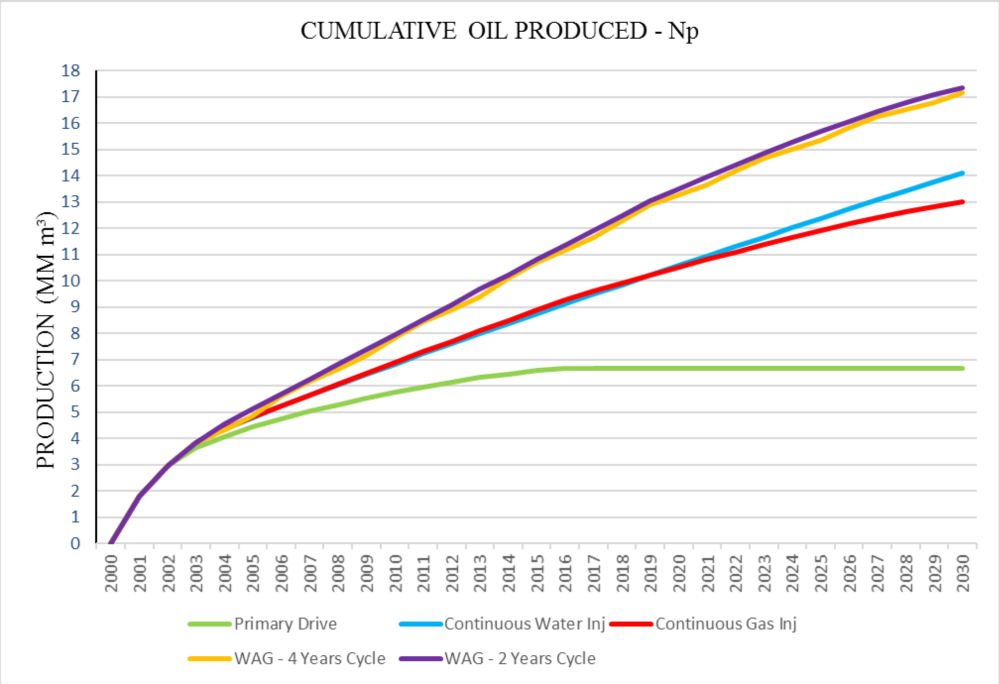

Figure 13. Cumulative produced oil for each scenario.

Table 6 shows a comparison between the results for NPV, Cumulative Oil Produced (N_p) and Recovery Factor (R.F.) of each case. It is easy to observe the large gap between the WAG injection and the other cases. The 4 years WAG cycle showed the best NPV value even with the 2 years WAG cycle presenting a large amount of oil produced after 30 years of production.

Table 6. Results comparison for Np and NPV.

Secondary Recovery Method	Cumulative Oil - Np (MM m³)	NPV (MM US$)	NPV Variation (%)	R.F.
Continuous Gas Injection	12.99	92.22	-	49,17
Continuous Water Injection	14.10	155.10	68%	53,37
WAG Injection - 4 Years Cycle	17.16	189.80	106%	64,95
WAG Injection - 2 Years Cycle	17.34	170.18	85%	65,63

5. CONCLUSIONS

The obtained results confirmed the better efficiency of the WAG method compared to the other cases analyzed in this study. All the simulations with some sort of secondary recovery method presented a recovery factor much higher than the primary drive mechanisms alone. The results reinforce the importance of the continuous search for an improvement in the secondary recovery methods.

In all the cases analyzed above, it is clear the outperformance of the WAG technique in both simulated cases. There is a significant difference in volume of oil and NPV value between the 2 different WAG cycles, but considerably larger when compared to single fluid injection.

CMOST had an important role in the single fluid injection method. The optimization tool helped to extend the life cycle of the reservoir that was being shut down after 17 years of production. With CMOST utilization the production could reach the original 30 years expected without reaching the GOR limit that was previously set.

As a suggestion for future studies, a better representation of the heterogeneity of the reservoir model could create favorable paths for the injected water flow; thus helping simulate a better displacement scenario for the water. Another point to be considered would be the variation of the WAG ratio to minimize the gas production in the last years of the simulation. The objective of this paper was the comparison between the mentioned secondary recovery techniques, however this is a wide area for studies and improvement in the oil and gas industry.

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