EOR modeling study applied to Ainsa

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Geosciences Division

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Abstract

Taking into account the characteristics of the reservoir and the fluid in place, the objective of this study is to find the optimal parameters to improve the total oil recovery in the Ainsa reservoir by setting up a production sequence based on improved water flood by the application of chemical processes. This study begins with a bibliographic revision to set up the constraints and the assumptions for the different chemical models. Numerical modeling is used to evaluate the efficiency of the applied injection processes. As most of the parameters are in general poorly known at reservoir scale, several hypotheses is tested in order to analyze their impacts over the final results. Finally, the most viable and profitable method in terms of final recovery is identified after evaluating different chemical systems as polymer, surfactant, alkaline-surfactant (AS), surfactant-polymer (SP) and alkaline-surfactant-polymer (ASP). A summary of the geology and the reservoir characteristics is introduced. The main part of this report deals with simulations of the different chemical treatments. Finally, by the comparison of the evaluated systems, the best enhanced oil recovery is obtained by an injection of a mobility control agent (Polymer), with a final recovery of 30% OOIP.

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1 Introduction

Enhanced oil recovery (EOR) is well-known method that helps increase the final oil recovery. Among all the procedures, chemical injection is applied in fields where water injection is no longer effective. The injection of polymer, surfactant and alkaline is an active research sector in the oil industry. Numerical modeling is used to appraise the efficiency of the applied scenarios even if there are large uncertainties on properties at reservoir scale.
Specifically the purpose of an alkaline-surfactant-polymer technology (ASP) is to produce incremental oil by reducing the water flood residual oil saturation. This technology help to reduce interfacial tensions with alkaline and surfactant while a mobility control is obtained using polymers (Vargo et al, 2000). Polymer makes the alkaline-polymer solution more viscous to improve sweep efficiency. Thus, polymer ‘‘brings’’ alkaline solution to the oil zone where the alkali cannot go without polymer. More oil can be displaced by lowered IFT owing to alkali-generated soap. In other words, alkali and polymer work together to improve both sweep efficiency and displacement efficiency.

Most of the treatments are successfully applied in pilot and large-scale projects. China is a pioneer in terms of chemical treatment research. After the success of polymer flooding in Daqing, core flooding and numerical simulation show that more than 20% OOIP incremental recovery can be achieved by ASP (Demin *et al.*, 1997). On the other hand, for Cambridge Minnelusa field, ASP flood is an economic and technical success with ultimate incremental oil of 1MMbbl at a cost of $2.42 per barrel. This success is due to an integrated approach of the application, including: reservoir engineering and geologic studies, laboratory chemical system design, numerical simulations, facilities design, and ongoing monitoring (Vargo *et al*, 2000). Considering these experiences, different treatments are applied to the Ainsa reservoir to determine the best scenario in terms of production.

The Ainsa reservoir model is built from data of the outcrop situated in Ainsa Basin (Figure 1) which is located in Spain, in the Sobrarbe region (Southern Pyrenees). It has 42 m of thickness and 750 m of length (Garrido, E. 2012).

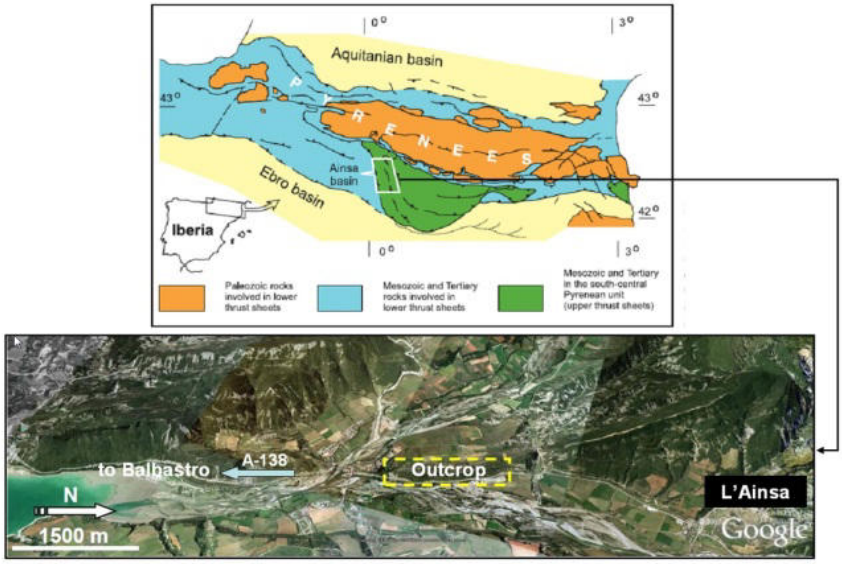

Figure 1 : Geological map of the Pyrenees with Ainsa basin position and the outcrop zone

Based on the characteristics of the reservoir and the fluid in place, the objective of this study is to find the optimal parameters to improve the total oil recovery by setting up a production sequence.

To achieve this objective, the following injection sequences are analyzed:

- Polymer
- Surfactant
- Alkaline-surfactant (AS)
- Surfactant-polymer (SP)
- Alkaline-surfactant-polymer (ASP)

All simulations are performed using the reservoir simulator Pumaflow 2015. Several cases are examined ranging from continuous injection with different periods of flooding, to cyclic injection with different intervals. In addition, appropriate chemical concentration is determined and the most profitable chemical combinations are analyzed.
As simulations done on the reservoir take few hours, only the main part of the reservoir is firstly studied using a three spot model (one injector and two producer wells). However, the most profitable cases are evaluated and compared, in terms of final recovery, over the whole model. As a rule, during this work all the hypotheses done for the field development are tested and analyzed to evaluate their impacts over the final results. Furthermore, all the established constraints and the assumptions for the different parameters come from published field experiences and EOR studies.
In this report we first describe the geology and the reservoir grid and the mains properties of the reservoir. In a second part, a detailed reservoir engineering study is presented using different chemical injection sequences. Finally, the results are discussed and the most profitable injection system, based on the comparison of future performance broadcast through different development plans is proposed.

1. Reservoir characteristics

1.1. Geology

Between the time of Eocene and mid Eocene, there is an intense geologic activity in the Pyrenees area marked by an intense sedimentation linked with the evolution of basins. These activities joined with a eustatic changes in Sea level are the cause of the different siliciclastic and carbonate platforms. The platforms are later eroded and deposit processes also occur resulting from turbiditic systems, (Garrido, E. 2012 and Figure 2).

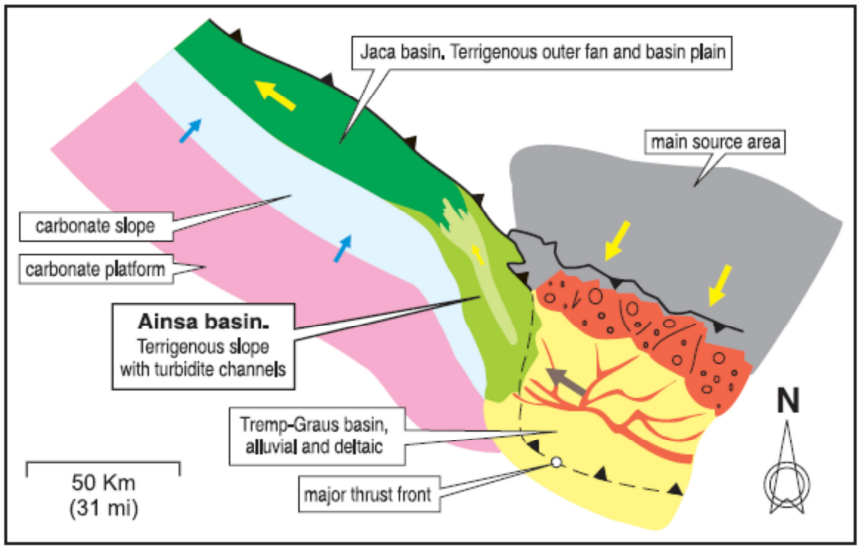

Figure 2 : Depositional setting of Ainsa sandstones.

Based on the field study carried out by Arbués et al. (2007), five facies are distinguished:

- Gravelly mudstones: Soft-sediment deformed material with a mudstone-dominated composition.
- Heterolithic packages and mudstone beds: Packages of layered mudstones and fine-grained sandstone beds up to 10 cm thick.
- Thick-bedded sandstones: Sandstone beds thicker than 10 cm with grain size ranges from very fine to pebble (up to 75% of sandstones correspond to medium to coarse grain size).
- Mudstone-clast conglomerates and conglomerates: Both facies are up to 1m thick. They correspond to conglomerates with a matrix of sand and limestone inclusions.

In this study particular interests are put on the sandstone and the heterolithic facies. Most of the recoverable oil remains in the sandstone facies. On the other hand, the reservoir potential of the heterolithics is affected by mudstone layers which have influences on the reservoir permeability and thus on the flow profile.

1.2. Model's characteristics

The proposed model is a black oil model and the cells are decomposed as follows (Figure 3):

- 64 cells in I (X length: 960 m)
- 70 cells in J (Y length: 1050 m)
- 145 cells in K (Z length: 50 m)

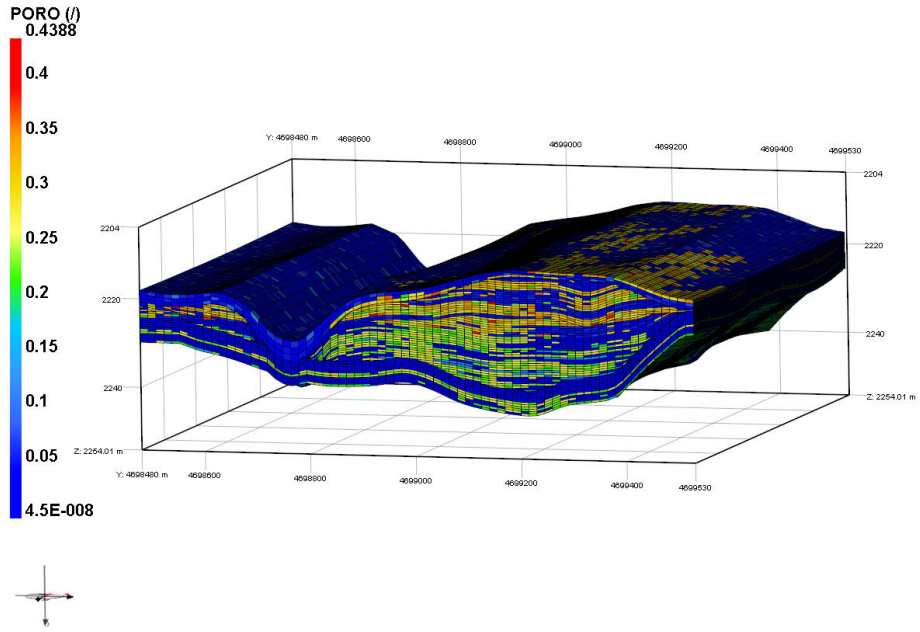

Figure 3 : Ainsa reservoir model

The distributions of the porosity and of the permeability are defined by facies. The reservoir facies porosity distribution goes within the range of 30% (Figure 4). In contrast, the no-reservoir facies porosity is classically lower and close to 0.5%.

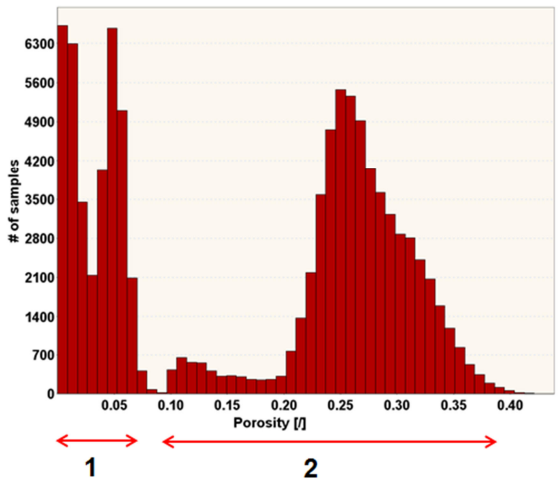

Figure 4 : Porosity distribution, no-reservoir facies (1); reservoir facies (2)

The table below summarizes the main properties of the reservoir and the fluids in place:

OOIP (hm3)	2,09
Pi (bar)	253,52
Ti (°C)	83
Pb (bar)	66,83
Swi (%)	15
Sorw (%)	24,5
WOC (MSL m)	5000
µo (cP)	13
µw (cP)	0.5

Table 1 : Reservoir characteristics summary

The figures 5 to 8 show the relative permeability and capillary pressure curves of the two facies that control the flow profile.

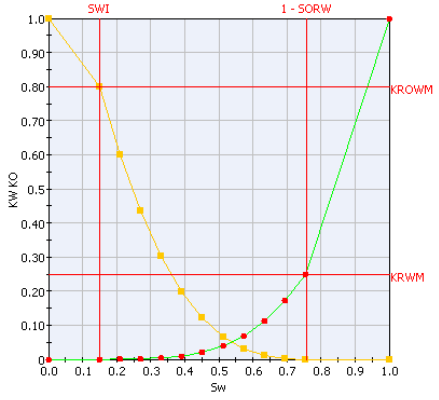

Figure 5 : Relative permeability curves Oil/Water for the sandstone facies

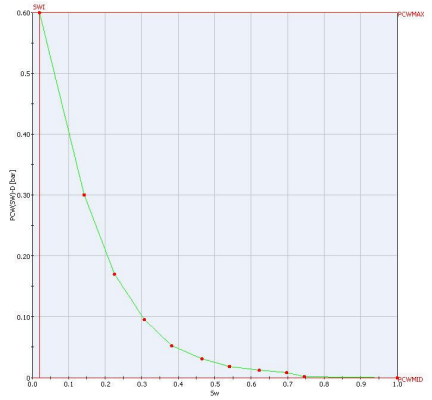

Figure 6 : Capillary pressure curve for the sandstone facies

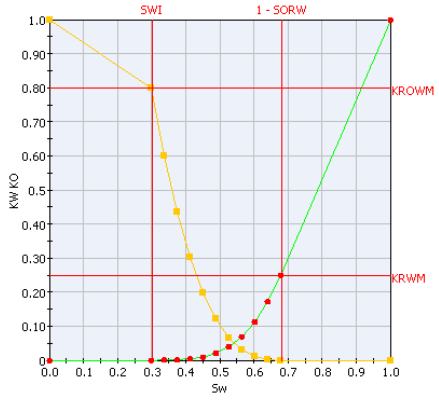

Figure 7 : Relative permeability curves Oil/Water for the heterolithics facies

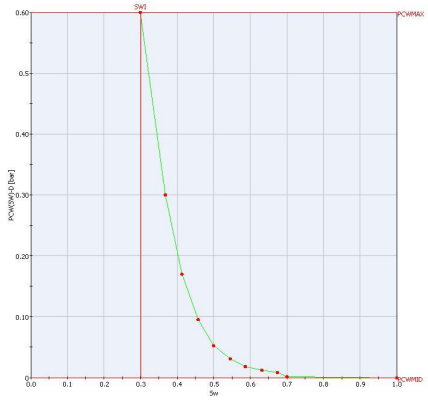

Figure 8 : Capillary pressure curve for the heterolithics facies

Relative permeability models and capillary pressure models are typical of water wet rocks. For all facies, water saturation varies between 30% (SWI) and 68% (1-SORW) except for sandstone whose water saturation varies from 15% and 75.5%. Although, extreme relative permeability values and capillary pressure values are the same for all facies, the change of water saturation interval makes the sandstone facies the best oil reservoir facies in term of oil volume storage and facility to produce it.

1.3. Sensibility studies of the field permeability distribution impacts

An important point is that the geological organization of the reservoir field is obtained thanks to an outcrop located close to the Ainsa town in southern Pyrenees, Spain. In this section the permeability distributions are not fixed. We address the following question: what is the impact of permeability distribution on the oil recovery considering a polymer slug injection. This question makes sense because the outcrop may be an analogue of different types of reservoirs. Indeed the outcrop helps to characterize the facies distribution but has a different geological story compared to a subsurface reservoir. Three different reservoirs are thus considered to be associated to three permeability distributions illustrated by figures 9 to 11, respectively corresponding to a non-altered reservoir, a fractured reservoir and an unconsolidated reservoir. The second permeability model results from an upscaling step in order to take into account the presence of fractures. The large permeability values of the third permeability model are due to unconsolidated facies. Models are respectively called “permeable”, “fractured” and “unconsolidated”.

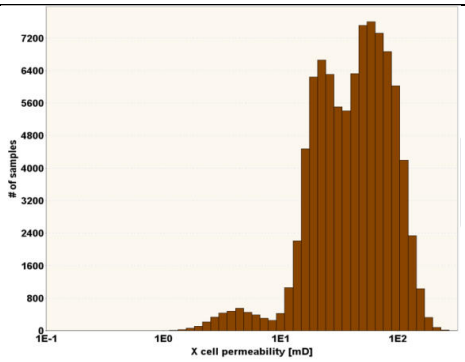

Figure 9: permeability distribution of the permeable model

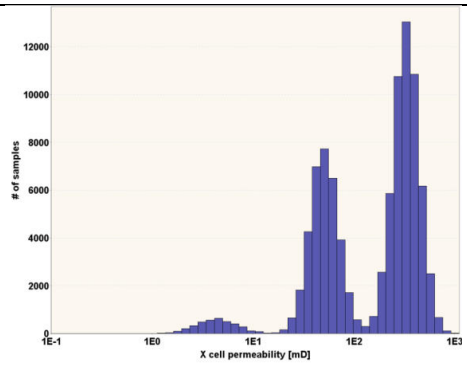

Figure 10: permeability distribution of the fractured model

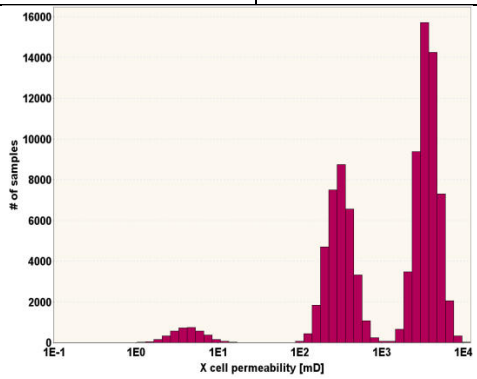

Figure 11: permeability distribution of the unconsolidated model

For this study, the size of the reservoir is reduced to his main part. The OOIP is 1.48 hm3 which is considered as reference to analyze each oil recovery. The reference case is a water injection implemented for 14 years with a pressure constraint of 500 bar. For each simulation, after a year of water flood, polymer injection treatment is carried out at the concentration of 1000 ppm for one year and then the concentration is graded to 500 ppm for another year. Finally, a water post-flush is injected until the end of the simulation (Figure 12).

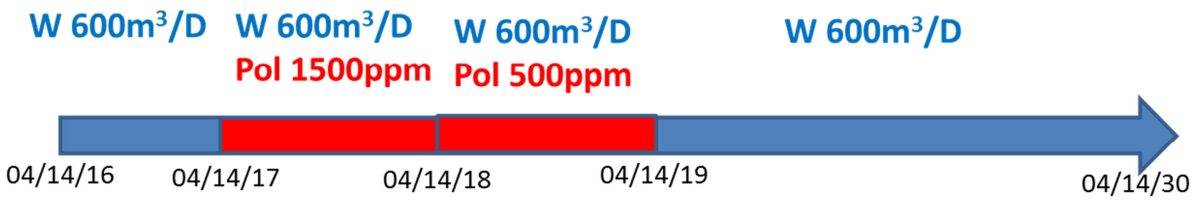

Figure 12 : injection sequence used for reservoir permeability sensitivity studies

The simulation results are indicated in the Table 3.

	Permeable reservoir	**Fractured reservoir**	**Unconsolidated reservoir**
PRODUCED OIL/Water (hm3) **Polymer case**	**0.398/0.428**	**0.383/1.194**	**0.273/1.303**
CWI (hm3) **Polymer case**	**0.862**	**2.012**	**2.466**
PRODUCED OIL/Water (hm3) **Water flood case**	**0.365/0.835**	**0.235/1.335**	**0.223/1.349**
CWI (hm3) **Water flood case**	**1.332**	**2.244**	**2.495**
%EOR	**9%**	**63%**	**22%**

Table 2 : polymer simulation results

I. First case : Permeable facies

By injecting 0.862 hm3 of water, 0.398 hm3 of oil are produced. The production of water reaches 0.428 hm3. Considering the permeable model polymer does not strongly help to better produce the reservoir oil. Only 9% of additional oil is produced using polymer injection. Due to weak facies permeabilities the pressure reaches quickly the imposed limit. As a consequence, water injection rate decreases during the water flood and decreases stronger when polymer is added to the solution. Therefore polymer injection does not have the attempted effect i.e. an increase of the cumulated oil production.

II. Second case: Fractured reservoir

After 4 years of production, 0.383 hm3 of oil and 1.194 hm3 of water are produced. The volume of water injected reaches 2.012 hm3. In this case, the oil recovery is improved by 63%. The ratio produced water volume (P/WF) is reduced by ~11% as well as the injected volume of water. Polymer injection is very interesting considering this case since %EOR reach 63%.

III. Third case: Unconsolidated sandstone

0.273 hm3 of oil is produced after injecting 2.466 hm3 of water. The high permeability allows the injection of higher volumes of polymer solution. However, oil recovery volume is decreased in comparison to the fractured case. A stronger water cut and a higher produced water volume contributed to this bad performance.

The curves below summarize the polymer performance for the three studied cases. Purple, red and yellow curves are respectively obtained using permeable, fractured and unconsolidated Ainsa models. Plain and dash curves stand for water flood or polymer injection sequences respectively.

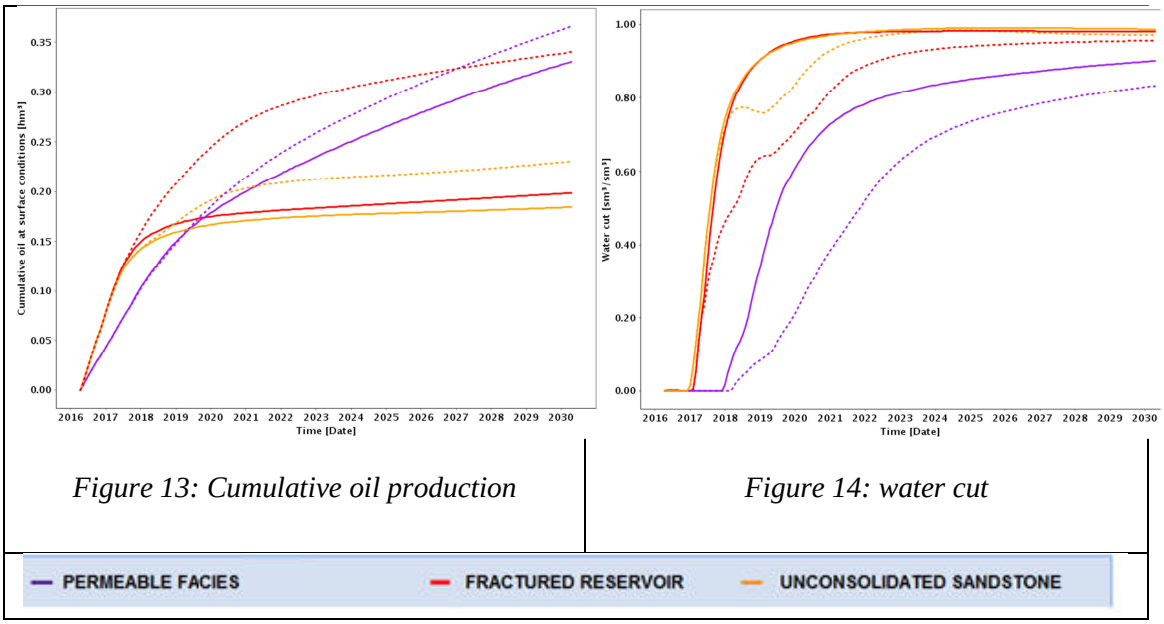

Figure 13: Cumulative oil production

Figure 14: water cut

As a conclusion, polymer impacts critically depend on the permeability distributions. If the reservoir permeability is too weak it will be difficult to inject polymer without damaging the reservoir or the injection wells. If the reservoir is too permeable earlier water breakthroughs or stronger water cut may be observed which have a negative impact on oil production. Finally, the fractured reservoir shows to be the best candidate for polymer flooding. Then, this permeability distribution will be considered for our field development studies and is presented in Figure 10. The reservoir permeability range is between 1 to 1000 mD. Three permeability picks may be observed with mean values of 5, 50 and 500mD correlated to facies distributions. Permeability is assumed transversely isotropic in any facies, with a vertical axis of rotational invariance. Vertical permeability is assumed smaller than horizontal permeability for heterolithics and mudstone-clast conglomerate by a factor respectively of 10 and 20 because of mudstone beds or inclusions.

2. Field development

2.1. Waterflooding

A water flooding is simulated for a period of 14 years. The oil is drained with a five-spot model. Long-range heterogeneities features, such as vertical contrasts, have significant effects on flow behavior (Figure 15).

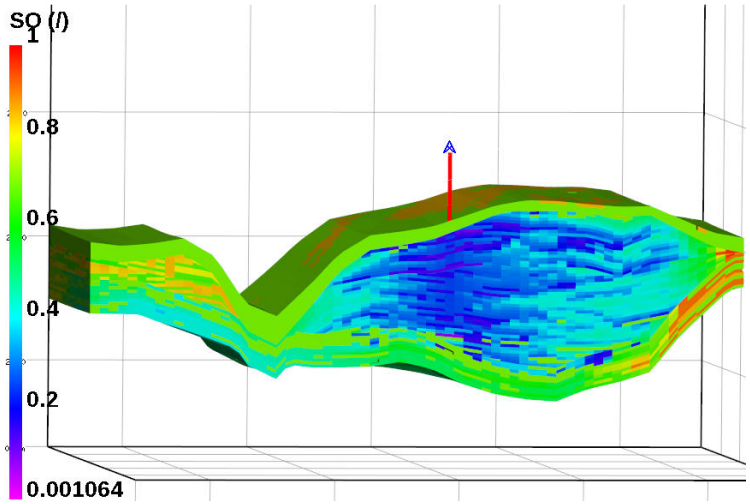

Figure 15 : Oil saturation at the end of the water flood simulation

The initial oil accumulation is 2.09 hm^3 of which 18% is produced at the end of the water flooding (final OIP 1.71 hm^3). However, from Figure 15, it is possible to see that there are zones with residual oil saturation larger than 40%. In addition a layering effect may be observed on Figure 15-16. The high facies and permeability heterogeneities of the reservoir contribute to form preferential flow paths that we call layering effect. Earlier water breakthroughs are the consequences of these preferential flow paths which may be reduced by using polymer injection as showed in the following section.

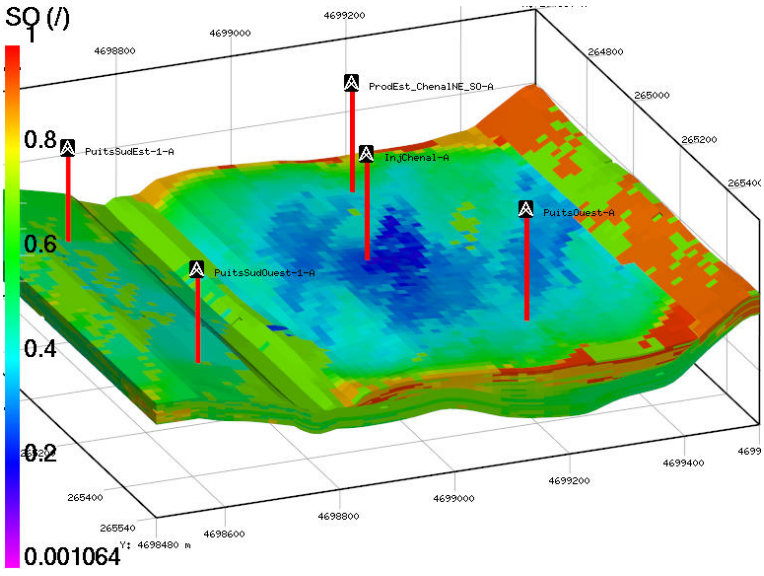

Figure 16 : Oil saturation at the end of the water flood simulation

2.2. Polymer injection

The following injection constraints are taken into account to perform the polymer injection simulation over the whole reservoir:

- The base case is a water injection implemented for 14 years with a pressure constraint of 500 bar.
- The polymer solution injection starts after a year of water flood for five years. Three scenarios are modeled (Figure 17):
  - A polymer injection of two years at 1500ppm (P1).
  - A polymer injection of five years at 1500ppm (P2).
  - A polymer injection whose concentration decreases as a time function. 1500ppm the first two year, 1000ppm for next two years and finally 500ppm a last year (P3).
- Finally, a water post-flush is injected after the polymer injection. The same pressure constraint is established.

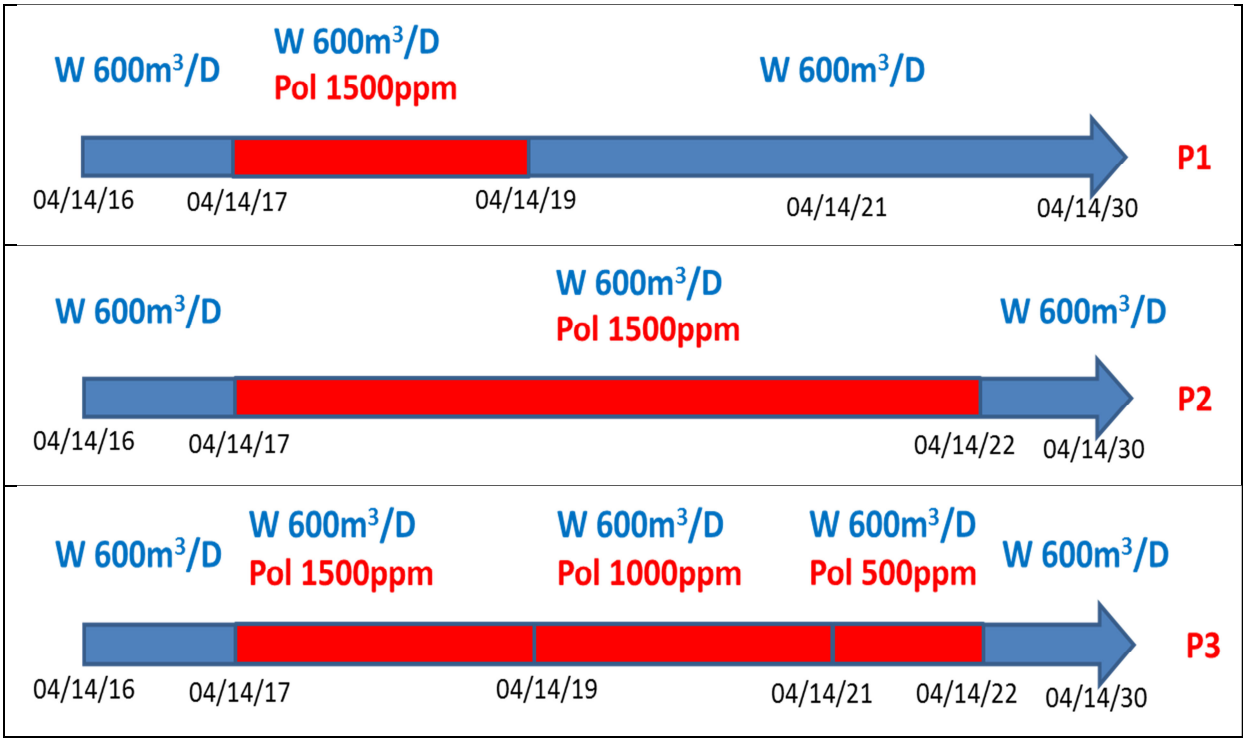

Figure 17 : polymer injection scenarios

In addition the polymer model takes into account the polymer adsorption (10 µg/g), a permeability reduction and an inaccessible pore volume (IPV=0.10). The IPV is due to a limited access because of the size of macromolecules or a wall exclusion effect because of the increase in the speed of the solution.

As a result an oil recovery of 24%, 32% and 30% is achieved depending on P1, P2 or P3 injection scenario, respectively. Thus the polymer injection is very efficient compared to the water flood (Figure 18). The water breakthrough impact is limited thanks to polymer (Figure 19) while the volume of water produced is reduced by 15%, 28% or 22% for P1, P2 or P3 respectively.

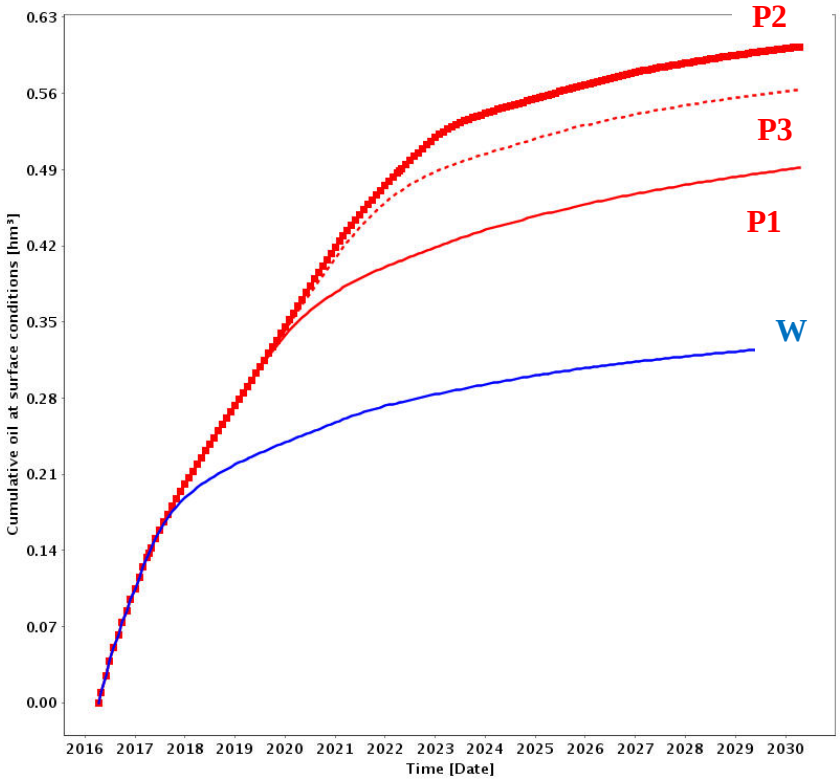

Figure 18 : Cumulative oil production for three polymer injection scenarios (P1, P2 ,P3) and a water flood injection (W)

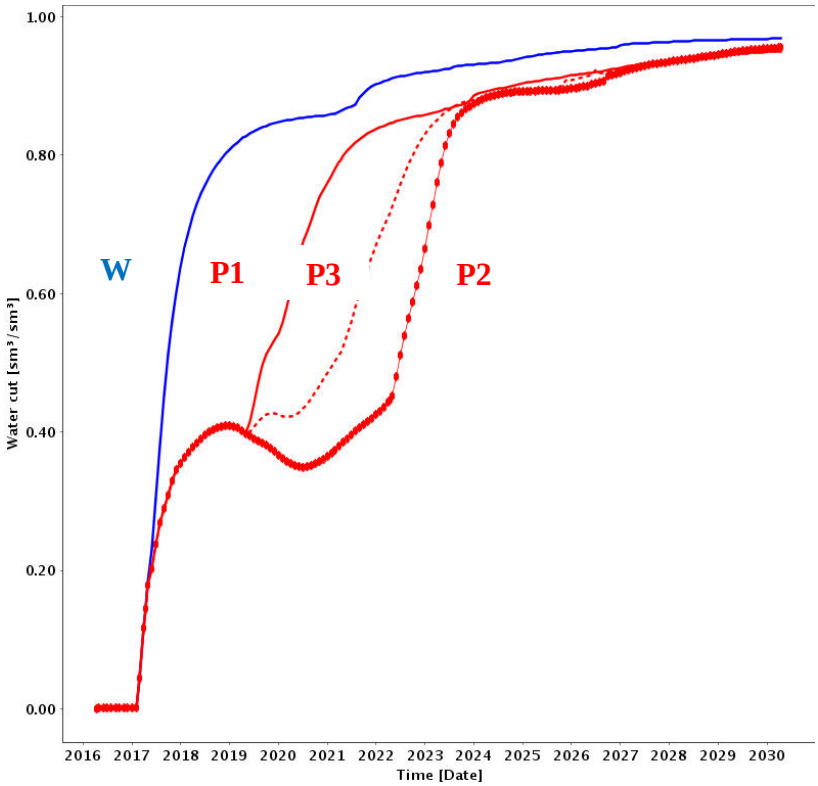

Figure 19 : Polymer effect over water cut

To limit the polymer injection volume while obtaining a good enhanced oil recovery the scenario P3 seems to be the best. At the end of the P3 simulation, it is possible to see that the low permeability zones are better swept (Figure 15 / Figure 20 and Figure 16 / Figure 21).

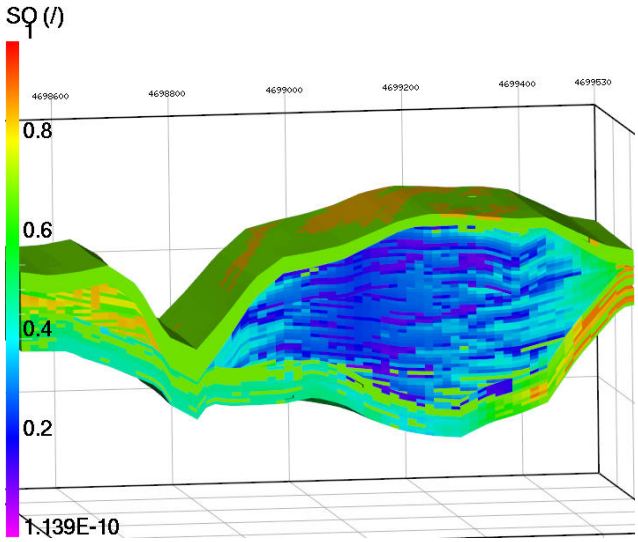

Figure 20 : Oil saturation at the end of the P3 scenario

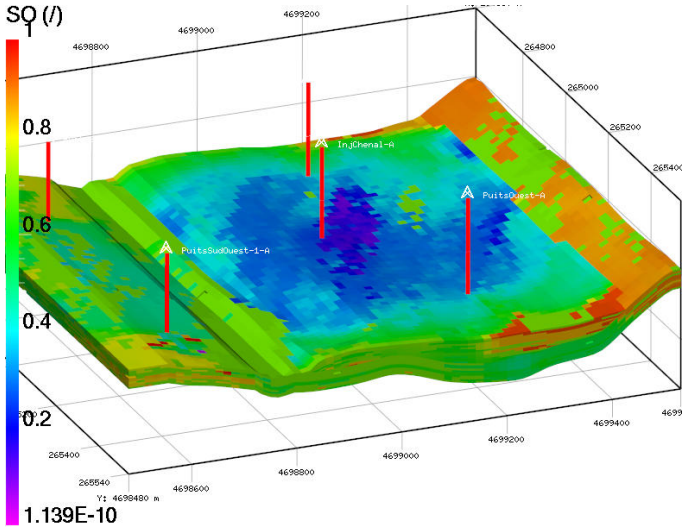

Figure 21 : Oil saturation at the end of the P3 scenario

To conclude this section, using polymer, an oil recovery of 30% is obtained. The injected volume of polymer may be optimized considering the injected concentration and slug volume. In this case there is not a sensible reduction of oil produced. Nevertheless, there are still zones where 40% of the oil remains in the reservoir after the polymer injection (Figure 21).

In order to reduce this saturation, different chemical systems; surfactant, alkaline-surfactant (AS), surfactant-polymer (SP) and alkaline-surfactant-polymer (ASP) flooding are tested to finally find the most viable and profitable method in terms of final recovery.

Several cases are examined ranging from continuous injection with different periods of flooding, to cyclic injection with different intervals. In addition, appropriate chemical concentration is determined and the most profitable chemical combinations are analyzed. For all of chemical combinations, chemical treatments begin after one year of water flooding.

2.3. Surfactant injection

A surfactant model is now considered. The impact on the solubilization of oil is modeled with dynamic Kr endpoints and chemical Kr curves. The impact on the interfacial tension is modeled based on the surfactant concentrations (Figure 22). The critical capillary number is established as 1E-6 (Figure 23). The effect of lowering the IFT on the chemical relative permeabilities is defined by dynamic Corey coefficients (Figure 24). A capillary pressure correction, a maximum adsorption of 50 µg/g and a Langmuir coefficient of 0.10 m3/kg is applied (Figure 25).

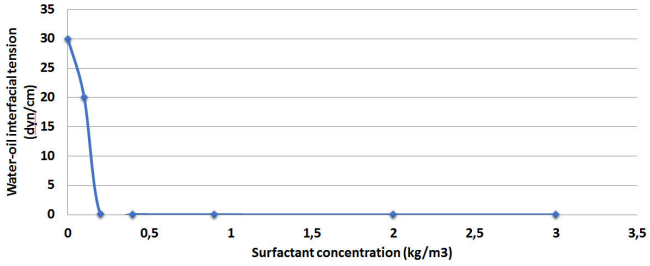

Figure 22 : Surfactant concentration effect on IFT

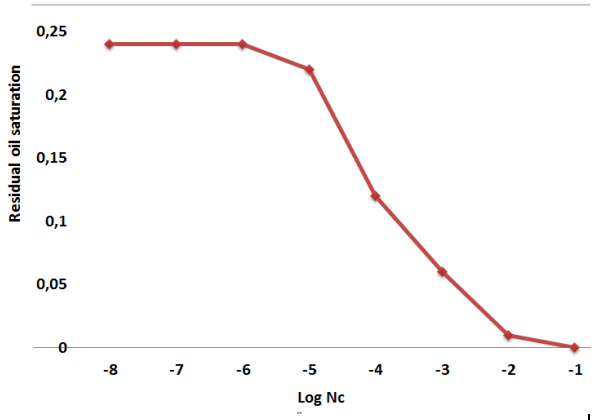

Figure 23 : Capillary desaturation curve

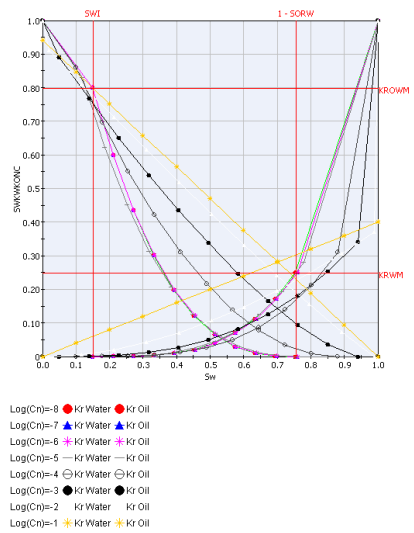

Figure 24 : Chemical permeabilities definition

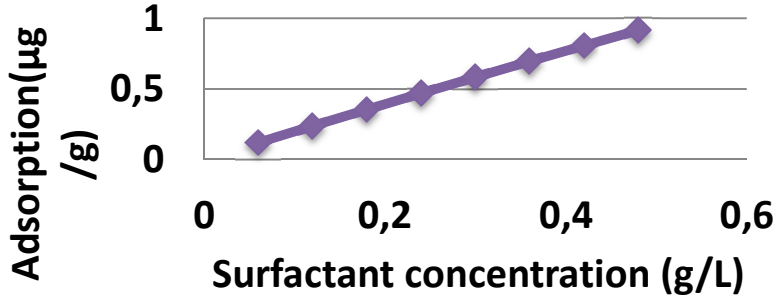

Figure 25 : Surfactant adsorption profile

A 2-year continuous surfactant injection at 2000 ppm is simulated (Figure 26).

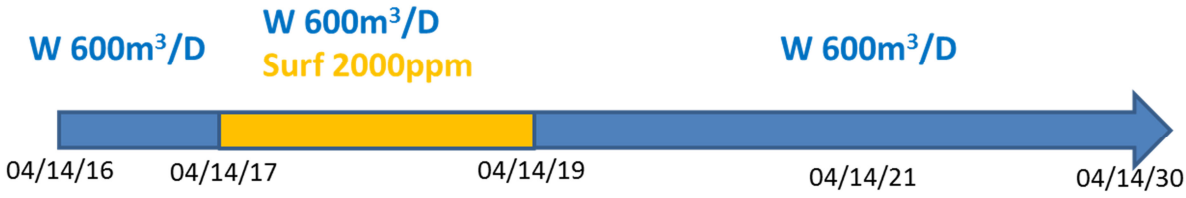

Figure 26: surfactant injection scenario

As a result, just 0.5% of improvement is achieved in comparison to water injection (Figure 27). The cause of this low recovery is the quick displacement of surfactant solution through the high permeability layers resulting in an early breakthrough. Nevertheless, one important observation is the very low oil saturations attained near the injection well as well as in the high permeability facies (Figure 28). The profile of surfactant concentration at the end of the simulation shows that no surfactant is left at the final time near the injector due to adsorption (Figure 29).

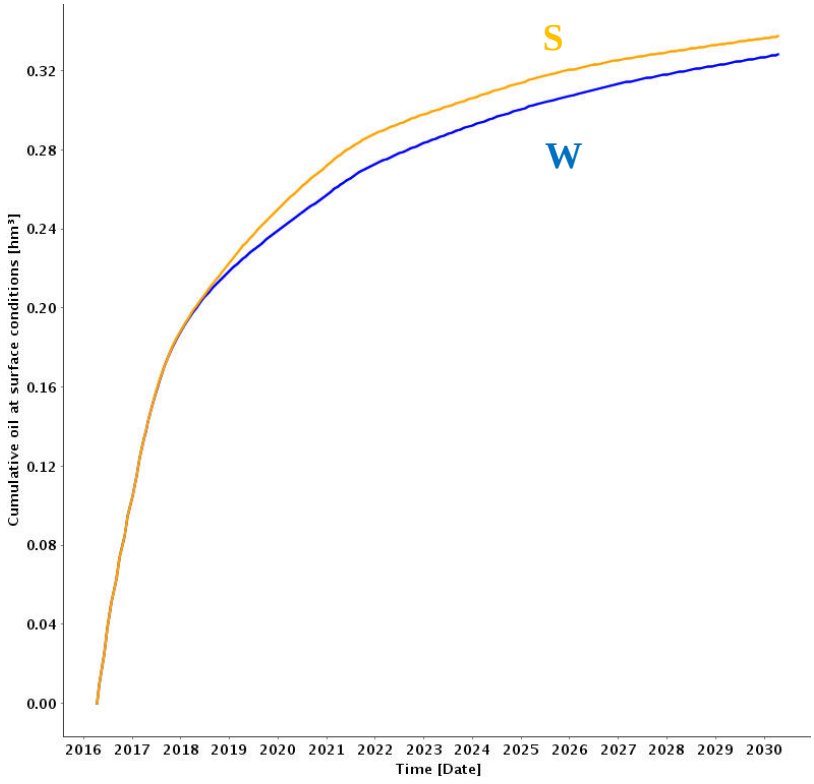

Figure 27 : Surfactant effect (S) on oil recovery compared to water flooding (W)

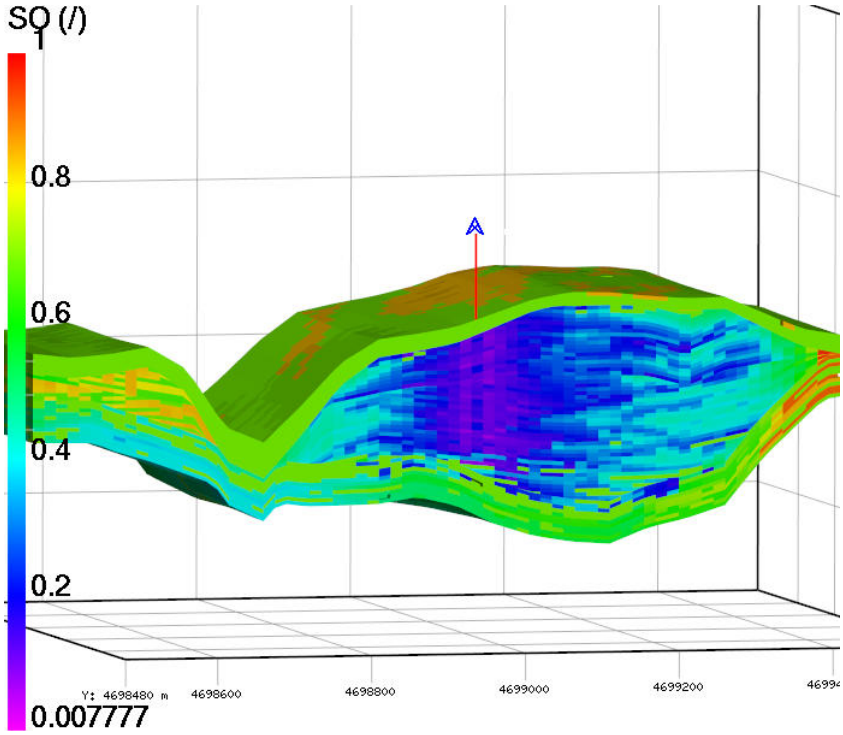

Figure 28 : Oil saturation near de injector after surfactant flooding

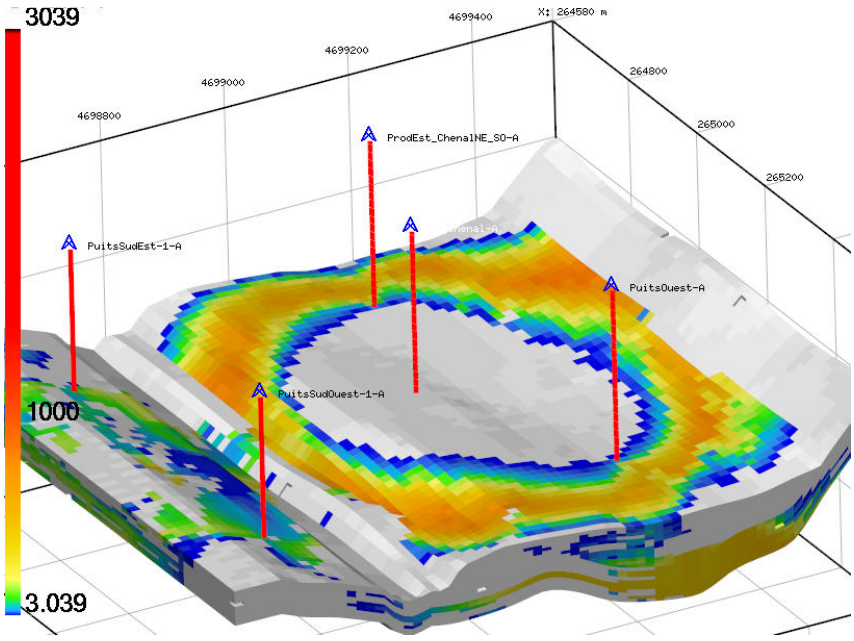

Figure 29 : Surfactant concentration in water profile

To conclude this section, incremental production obtained using surfactant is closed to 0.5%. The high permeable layers are the primary reason of the poor final performance. As a result, the polymer injection seems to be more efficient because polymer helps to control the water mobility. In a word high permeability layer flows are reduced contributing to a better sweep of lower permeable layer. In addition as surfactant adsorption is not important a simultaneous alkaline surfactant injection gives the same result as the surfactant injection. However, by combining polymer and surfactant, a better recovery could be achieved and this will be studied in next section.

2.4. Surfactant – polymer flooding system

As seen section 2.2, the mobility control is the key parameter to prevent layering effects while helping to obtain a good sweep of the reservoir. By applying a combined polymer/surfactant process, we look for ways to improve sweep efficiency while keeping the flow displacement efficiency.
The chosen polymer scenario (section 2.2) is applied. During the second polymer injection surfactant is simultaneously injected (Figure 30).

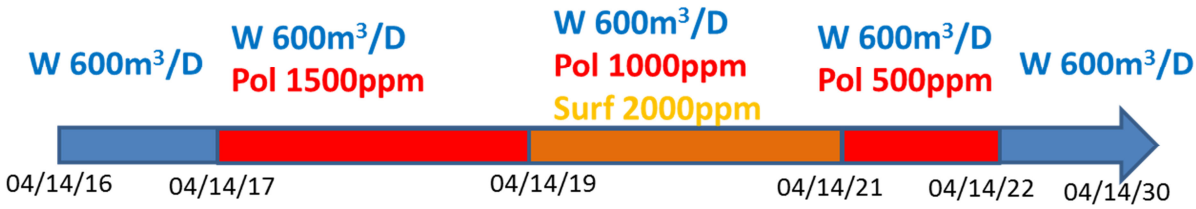

Figure 30:SP injection scenario

The figure below shows the incremental recovery of this sequence. By applying the optimal parameters in terms of surfactant concentration found in the section 2.3., 45% OOIP was recovered with a 4-year SP injection. (Figure 39).

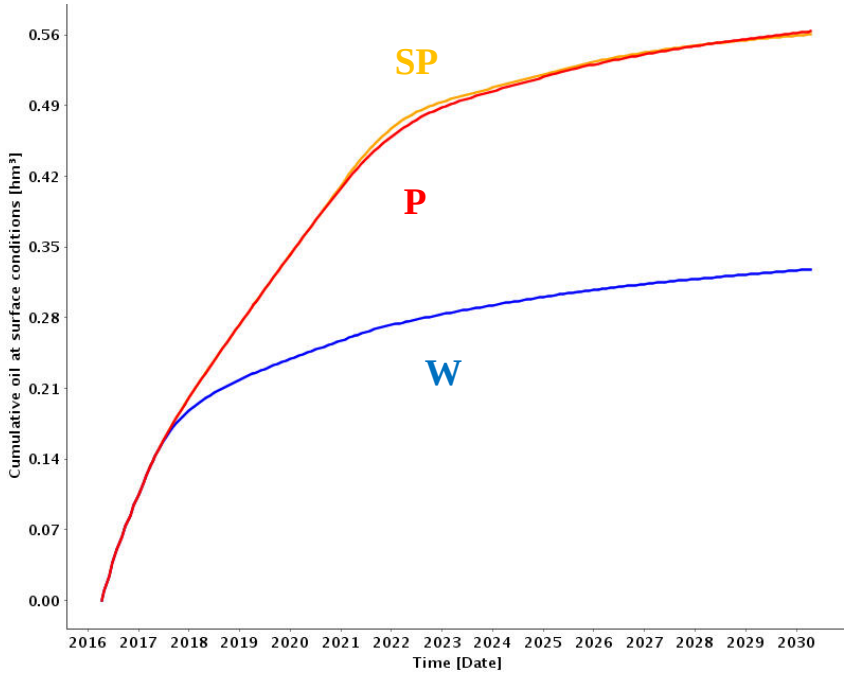

Figure 31: cumulative oil production of Water, Polymer and polymer/Surfactant injection

As a conclusion, by combining the effect of mobility control given by the injection of polymer and the reduction of interfacial tension obtained by the injection of surfactant, no significant increment of recovery is observed comparing to polymer injection. To validate this result we now inject 15g/L of alkaline with the surfactant. The injection scenario is given Figure 32.

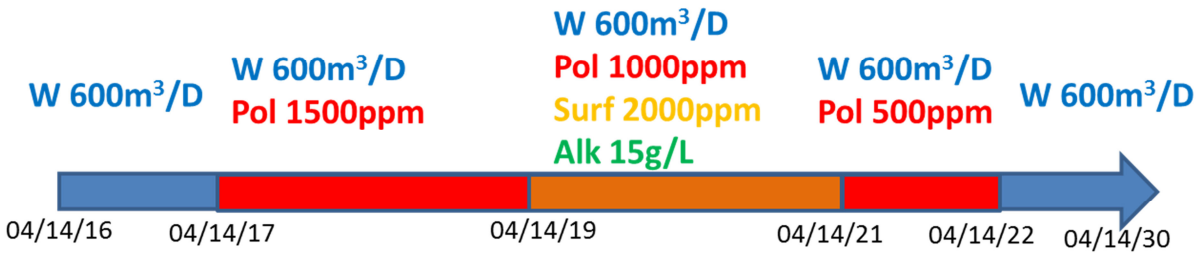

Figure 32: ASP injection scenario

The following curves resume the different injection scenarios. As a result the use of polymer increases significantly the oil production. In another side no significant incremental production is observed if surfactant or alkaline are added to the polymer.

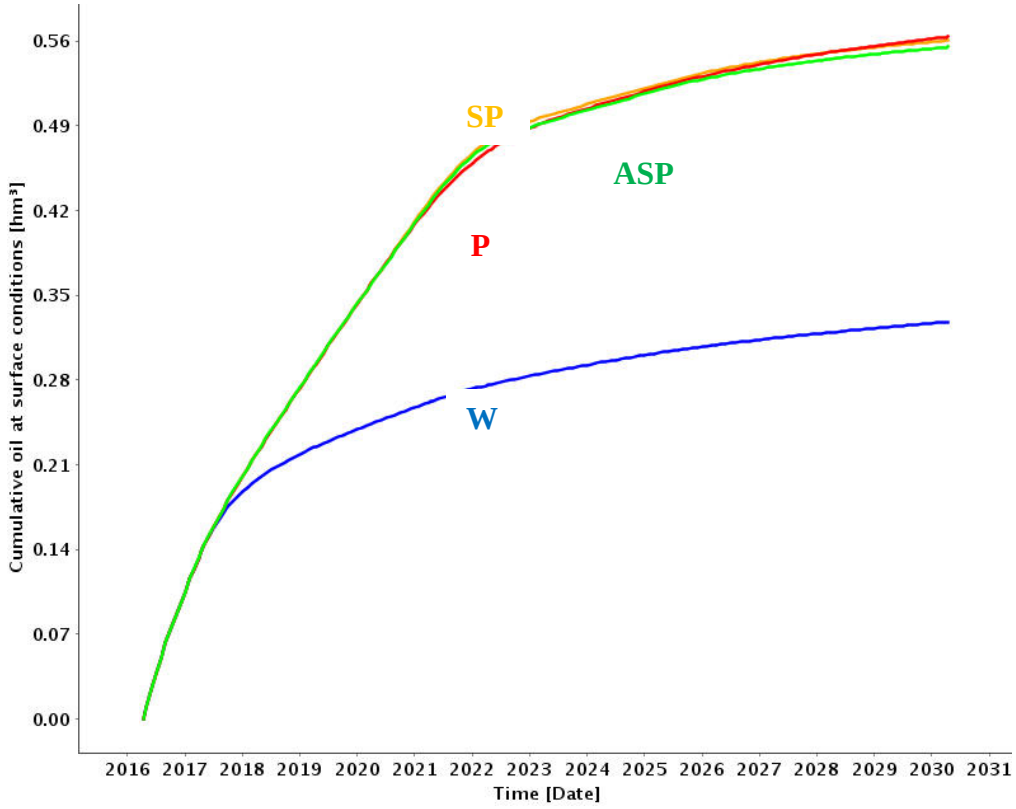

Figure 33 : cumulative oil production of Water, Polymer, Polymer/Surfactant and Alkaline/Polymer/Surfactant injection

2 FINAL EVALUATION

Table 4 shows the percentage of oil recovery. Among all the scenarios tested, the best oil recovery is achieved through a polymer flooding with an oil recovery of 30%. Polymer helps to produce 210 sm^3/day during 4 years. Considering the same period a water flooding only produce 50 Sm3/day (Figure 34).

Chemical injection	Produced Oil (hm^3)	% oil recovery
Water flood	**0.375**	**18%**
Polymer	**0.62**	**30%**
Surfactant	**0.39**	**19%**
AS	**0.39**	**19%**
SP	**0.62**	**30%**
ASP	**0.62**	**30%**

Table 3 : Comparison of chemical treatments tested

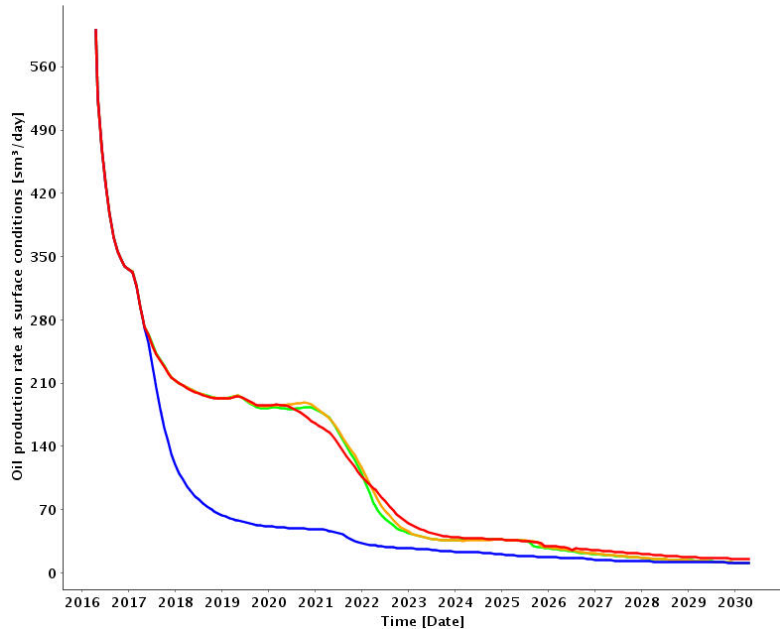

Figure 34: oil production rate for Water, Polymer, Polymer/Surfactant and Alkaline/Polymer/Surfactant injection scenario

According to the obtained results, the injection of polymer is the main parameter to increase the oil recovery due to the reservoir heterogeneity. As a result on Ainsa field, surfactant injection is not profitable without a mobility reduction agent. Without polymer in the surfactant slug, a layering effect does not allow to obtain a good reservoir sweep. It is important to remark that for polymer and surfactant models, adsorption reduced their efficiency. However, the fact of testing adsorption helps to decide if a method to reduce adsorption is profitable.

3 CONCLUSIONS

The exposed results show that the initial water flooding recovery (18%) may be improved by the application of an appropriate chemical treatment. To develop this reservoir, through an interesting technique, an improved injection sequence is applied and the development of the reservoir is forecasted. The most profitable system found is a polymer injection which reached an oil recovery of 30% OOIP over the whole reservoir (Figure 35). The volume of produced water is reduced by 22%. Furthermore, a cyclic injection may be applied if there are economic constraints since the quantity of chemicals may be reduced by a half.

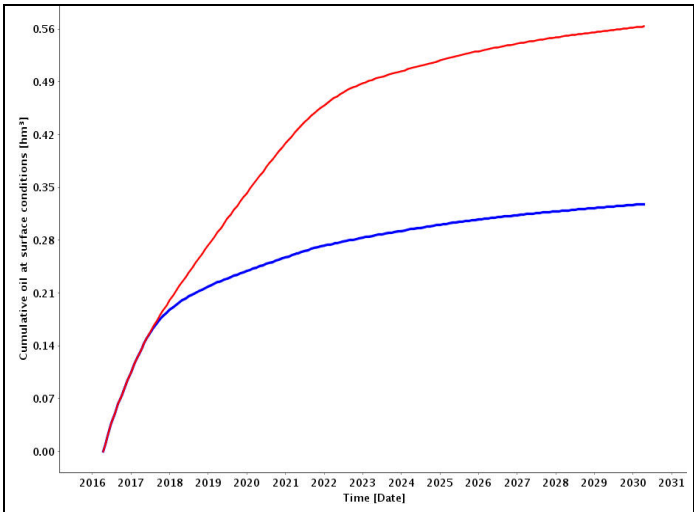

Figure 35 : cumulative oil production for water and polymer injection scenarios

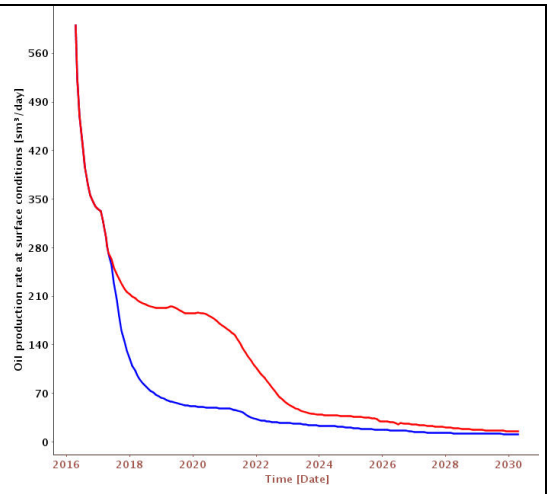

Figure 36 : oil production rate for water and polymer injection scenarios

The figures below show the variation in oil saturation after the water injection and SP system. Both allow the comparison in terms of residual oil saturation. It's clear that the polymer injection optimizes the reservoir drainage.

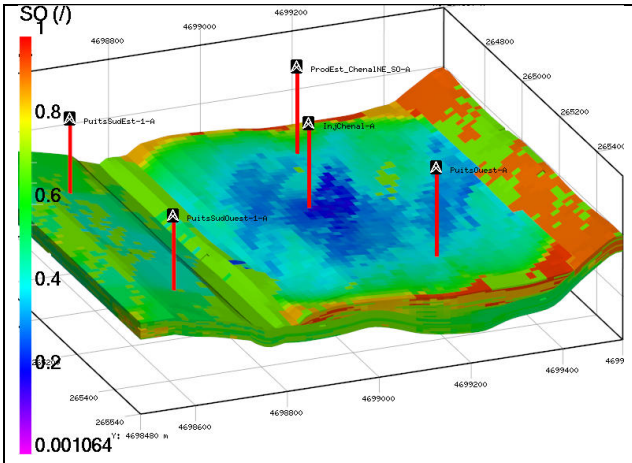

Figure 37 : Water flooding residual oil saturation

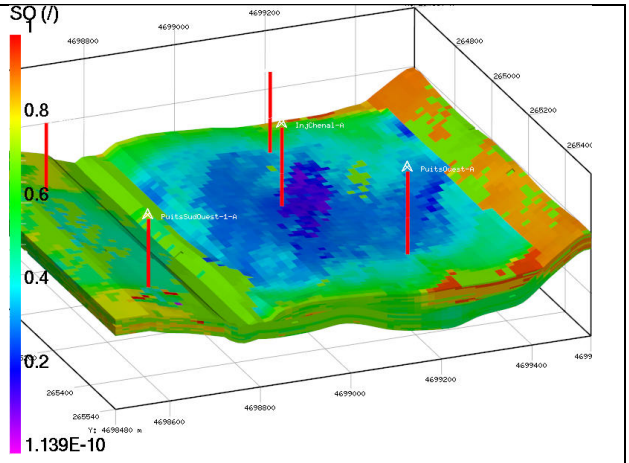

Figure 38 : Polymer flooding residual oil saturation

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